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Economics of Third-Party Central Heating Plants To Supply the Army

by
Alan M. Cody
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This report analyzes the feasibility of using third-party energy supply contracts to build, operate, and maintain central heating plants on Army installations. It defines the economic and technical factors driving the third-party contract process, the vulnerability of these factors to change, and the conditions that would foster economical third-party heat supply.

The content and structure of third-party contracts, and typical participants, are characterized. The responsibilities, roles, objectives, and risk factors of each contract party are also defined. To determine the impact of key contracting variables on overall project viability, financial modeling of life-cycle costs for third-party versus Government-owned heat supply plants was performed, and the results are included. Finally, a checklist for identifying preferred third-party projects is presented.

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FOREWORD

This study was conducted for the U.S. Army Engineering and Housing Support Center (USAEHSC) under Project 4A162781AT45, "Energy and Energy Conservation"; Work Unit DO-006, "Coal Use Technologies." The USAEHSC Technical Monitor was B. Wasserman, CEHSC-FU.

This research was performed by the Energy Systems Division (ES), U.S. Army Construction Engineering Research Laboratory (USACERL). Dr. David M. Joncich is Chief, ES. Alan Cody is with A.D. Little, Inc.

LTC E.J. Grabert, Jr. is Acting Commander of USACERL, and Dr. L.R. Shaffer is Director.

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1 INTRODUCTION

Background

Under current law,[1] Department of Defense (DOD) agencies may enter into contracts for up to 30 years to purchase energy from private parties, known as third-party contractors. The Army is very interested in third-party financing and operation of its central heating plants as a possible way to reduce capital costs. However, to date, the Army has awarded only one such contract (Fort Drum, NY), despite requirements that all large heat supply projects be reviewed for possible third-party contracting.[2] This situation is due in part to the Army's lack of familiarity with third-party business practices and to the industry's reluctance to enter an unproven venture. The 1986 Tax Reform Act[3] introduces an additional element of uncertainty as tax credits and accelerated depreciation previously available to third parties have been eliminated.

To improve opportunities for executing these contracts, it is necessary to analyze third-party financing activities as applied to the military. It is known that geographic location, regional population density, and physical size of the plants are considerations for profitability, along with local markets for both products and byproducts. However, what combination of conditions must occur to make third-party financing feasible? Specifically, the Army needs to know:

1. What economic and technical factors drive the third-party contract process?
2. How vulnerable are these factors to change?
3. What conditions would ensure economical third-party heat supply?

To answer these questions, the Army asked the U.S. Army Construction Engineering Research Laboratory (USACERL) to study third-party contracting and recommend methods of identifying the best projects to pursue.

Objective

The objective of this study was to analyze the economic outlook for third-party contracting to supply central heat at U.S. Army installations.

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[1] Public Law (PL) 97-214, *Military Construction Codification Act* (12 July 1982), 96 Stat. 153.
[2] Defense Energy Program Policy Memorandum (DEPPM) 88-1, *Defense Facilities Energy Selection*, 1987.
[3] PL 99-514, *Tax Reform Act of 1986* (22 October 1986), 100 Stat. 2085.

Approach

USACERL conducted direct research with private companies involved in third-party contracting. In addition, a financial analysis was performed to assess the prospect for future development of third-party heat supply. This approach involved four major steps:

1. A review of the one existing third-party contract awarded by the Army at Fort Drum, analysis of the bid solicitations for a project at New Cumberland Army Depot, PA (no bids were received), and interviews with Navy and Air Force personnel responsible for third-party contracting.

2. Interviews with private organizations participating or seeking to participate in third-party contracting to characterize their business objectives and practices, and to ask them how they believe third-party contracting could be improved.

3. Development of a financial model to estimate the relative life-cycle costs of third-party and Government-owned heat supply plants under various assumptions.

4. Preparation of a checklist for assessing a potential third-party heat supply project.

Scope

This study is limited to the following facets of third-party contracting:

- Content and structure of third-party contracts
- Participants in third-party contracting, their responsibilities, roles, and objectives
- Financial modeling of life-cycle costs for third-party versus Government-owned heat supply and sensitivity of these costs to changes in key variables
- Risk factors for Government and third parties
- Factor for identifying preferred third-party projects.

Mode of Technology Transfer

This information will be transferred to installations as an Engineer Technical Note (ETN).

2 THIRD-PARTY CONTRACTS: AUTHORITY AND STRUCTURE

Enabling Legislation and Policy Guidance for Third-Party Heat Supply

To understand the issues involved in third-party contracts for supplying central heat, it is helpful to review the legislative authority making these contracts possible.

Public Law (PL) 97-214 authorizes DOD to enter into contracts for periods of up to 30 years to purchase energy or fuel. The law:

1. Provides for payment of the cost of these contracts in any year from "annual appropriations for that year."

2. Restricts fuel use by prohibiting construction (on land under DOD jurisdiction) of facilities that use oil and gas with an input heat rate of more than 50 MBtu/hr.*

3. Requires that these contracts be awarded only after approval of the Secretary of Defense and notification of the Committees on Armed Services and Appropriations of both Houses.

The law, therefore, provides a legal basis for substituting annual payments by DOD for energy services to private parties in the case of larger initial capital expenditures. It also applies to the Operation and Maintenance, Army (OMA) costs of Government-owned and operated facilities under Military Construction, Army (MCA) programs.

Defense Energy Program Policy Memorandum (DEPPM) 88-1 provides further third-party funding guidance and advice to the military services and Defense agencies.[4] It requires evaluation for possible third-party contracting of all new and more than 50 percent rehabilitations of heat plants with thermal energy input of 100 MBtu/hr or greater within the continental United States. Third-party financing for other projects may be considered including: projects with total thermal input of under 100 MBtu/hr, less than 50 percent rehabilitations, projects outside the U.S., and projects constructed solely to provide standby or emergency backup.

Also in connection with third-party funding, DEPPM 88-1 states that:

> Careful evaluation of commercial alternatives must be made to insure that the basic mission of the installation is not compromised in any way and that the purchase of needed utility energy is at the lowest available life-cycle cost (defined as all costs annually over the contract term discounted at 10 percent to present value) when compared with a Defense financed plant and other commercial alternatives.

U.S. Army Corps of Engineers (USACE) Huntsville (AL) Division has been given by USACE Headquarters the responsibility of funding and establishing priorities for third-party contracting. It acts as point of contact for all third-party proposals. As such, it has prepared a Management Plan (December 1985) for third-party contracting and established a standard contract format and basis for evaluating third-

* Fuel use restrictions have been removed in 1987 by repeal of the Fuel Use Act, which had prohibited the use of oil and gas in new electric generating facilities and new industrial boilers with a fuel input heat rate of 100 million Btu/hr or more, and in new boiler plants with a rate of 250 million Btu or more. DOD policy also was changed in FY87 and FY88 Defense Appropriation Bills to allow the choice of the most economical fuel, provided that Government-owned facilities have at least one "stockable" fuel (see title 10-Sec 2690 rev. of PL 97-214).

[4] Defense Energy Program Policy Memorandum (DEPPM) 88-1.

party proposals. The plan assumes a 25-year contract with the option to renew for 5 additional years. This plan also requires continuous "surveys of Army installations to identify potential third-party projects."

The third-party heat supply program could benefit the Government by better matching cash payments with the timing of services received, avoiding large capital expenditures and reducing budget requirements. The program can be successful, however, only if private parties can own and operate heat plants with economic advantages not available to a Government-owned and -operated facility. Whether these advantages exist is discussed in Chapter 4.

Current Contract Structure

The third-party contract structure was analyzed to identify issues likely to affect the cost, reliability, and availability of outside heat supply services compared with Government-owned and operated plants. The goal was to establish a basis for analyzing these issues to identify minimum conditions for an effective contract. In addition, the current contract structure was evaluated to determine if alternative structures and terms would reduce risks to DOD and improve the quality and supply of third-party bidders.

To analyze the contract structure, USACERL reviewed the contract for third-party heat supply services awarded at Fort Drum to Jones Black River Services. In addition, the third-party contract bid solicitation and amendments issued for the New Cumberland Army Depot project were analyzed. USACERL also discussed the contract structure with Huntsville Division's Energy Program group. The review concentrated on aspects of the contract structure that affect the relative costs of heat supply from third-party contractors compared with Government-owned and -operated central heat plants. Contract terms affecting reliability and risk for both the Government and the contractor were examined.

The contract structure review covered:

- The third-party contractor business organization
- Services provided
- Pricing
- Termination of contract
- Basis for bid evaluation.

Each item is discussed below.

Third-Party Contractor Organization

The parties to third-party heat supply contracts are the U.S. Government and a private business organization such as a corporation or partnership formed by one or more parties for the purpose of investing in, building, and operating a heat supply facility. The private organization contracts with the Government and assumes responsibility for design, financing, construction, fuel procurement, and

operation of a central heat supply plant from which thermal energy is sold to the Government over a period of 25 to 30 years.

A single business organization is needed to contract with the Government and meet the existing requirements of third-party contracts. The fivefold purpose of the business organization is to:

1. Provide a legal entity that can enter into a contract with the Army and subcontracts with others.

2. Allow borrowing of money secured by ownership of the physical assets used for the project.

3. Provide a legal entity that allows some or all of the parties involved to invest in the project.

4. Account for and allocate the profits of the project to its investors in return for cash or other value such as services or reduced equipment cost.

5. Hire and compensate suppliers and operating managers for the project.

Three types of business organizations are available to private parties who organize to bid on and fulfill third-party contracts:

- Partnerships
- Service contracts
- Leases.

Most bidders on third-party contracts believe that the partnership is the preferred form of business organization for heat supply contracts for the following reasons:

1. Partnerships avoid double taxation of profits by passing tax losses and liabilities directly to each partner's own tax return. In contrast, profits incurred through a corporation, if used for the heat supply contract, would be taxed twice--when earned in the venture and again on dividends when distributed to the owners.

2. A partnership also allows each partner's percentage of profits to be negotiated relative to value contributed, whereas in a corporation profits are allocated and distributed in direct proportion to the initial capital contributed by each party.

3. A partnership is organized by an agreement among general and limited partners for a specific period of time (usually corresponding to the life of the project) and partnership interests are difficult to transfer.

4. The partnership is authorized to borrow money for the project using the project's assets as security and enter into other activities needed to manage a third-party project.

The partnership includes general and, in many cases, also limited partners. It is managed by a general partner(s) who can be a corporation or an individual. Limited partners usually contribute only money and do not manage the project. The general partner usually has unlimited liability for the actions of the partnership whereas the liability of limited partners is limited to their investment. Thus, it is essential for the Government to ensure that general partners or the corporation have enough capital assets to ensure contract performance and provide a recourse for the Government in case of default. The typical

practice is to require submission of a personal financial disclosure statement (for individuals) or audited financial statements for a corporation. More importantly, the general partner who will run the partnership should have experience in designing, constructing, and operating several similar plants.

The private party business entity for the Fort Drum project, Jones Black River Services, is a joint venture partnership of J.A. Jones Construction, Duke Power, Westmoreland Coal, Prudential, Ahlstrom Capital, Fort Drum Cogenco, Inc. (subsidiary of Niagara Mohawk), and Pyropower. These partners contributed capital, expertise, and equipment services in return for a negotiated percentage interest in the profits of the partnership. The profit was derived from both the heat supply contract with the Army and cogenerated electricity sold to Niagara Mohawk.

In the case of a corporation, unlike a partnership, the contractor's liability to the Government and lenders may be limited to the assets of the project in the event of default or other problems. A partnership, therefore, gives the general partner an incentive to avoid default and loss of assets--objectives that are consistent with those of the Government in third-party contracting. The general partner meets this incentive by obtaining insurance to cover most major risks such as fire and accidents, and prudently managing construction and operation of the third-party project. A detailed discussion of the pros and cons of alternative business organizations is available in the literature.[5]

Contract Services Provided

Third-party contractors, operating through their business organization, supply thermal energy in the form of steam or high-temperature water to military installations under long-term contract as authorized by PL 97-214. This section summarizes the most important provisions of the contract form for third-party heat supply to Fort Drum and for bid solicitation in the New Cumberland project.

Allowed design and construction time from notice to proceed is approximately 24 months and term of heat supply is 23 years following that for a total contract term of 25 years. An option to renew the contract upon mutual agreement for an additional 5 years is included. The contract provisions specify:

- Steam pounds per hour and pressure input to base distribution systems
- Thermal output to be provided, in terms of peak hourly Btu requirements and total annual requirements
- Fuel(s) mix for generation of heat both for primary and backup fuel capacity
- Construction and operating performance quality standards, including boiler availability of 95 percent (85 percent is a more realistic figure for industrial boilers).

The contractor's responsibility is to deliver thermal energy to an existing base distribution system. Since third-party contracts are for central heat plants, this implies that the base will have a concentrated thermal load or district heating. Third-party contracting responsibility would be difficult to isolate and monitor separately from Government-owned assets such as building boilers and distribution systems. Third-party contracting with prepackaged small cogeneration systems is possible but is not within the scope of this report; it is more a direct sale of equipment than development of a central heating plant.

[5] J.F. Weston and E.F. Brigham, *Managerial Finance* (The Dryden Press, 1981).

The contractor also enters into a land lease for a site provided by the Government or obtained by the contractor, and pays for utilities and water at the site provided at current rates by the Government or local utility. Third-party contracts may, at the bidder's option, be bid as cogeneration projects. This power is generated along with the thermal energy supplied to the Government. In the case of cogeneration, the bidder also enters into separate agreement to sell its electrical power to the local electrical utility. Contracts for electrical power sales are available over a term negotiated with the utility and to preserve FERC qualification would be the same as for thermal energy (25 years).

No special problems or qualifying standards for FERC appear unique to third-party contracting with DOD (see 18 CFR 292, Subpart B[6] for more information on qualification criteria). Qualification, however, does require that the third party have at least one thermal customer in order to be able to sell the electrical output, and if it loses that customer, it is "dequalified." It also precludes electrical utilities from owning more than 50 percent of the equity in a cogeneration project. The impact of cogeneration on life-cycle costs of thermal energy is discussed in more detail in Chapter 4.

Pricing

Third-party heat supply to the Government is priced by a monthly capacity charge for all costs not directly related to actual steam consumed plus a fuel charge based on the amount of metered steam or high-temperature water actually consumed. Each charge is escalated using producer price indices (PPIs). The PPI is specified for industrial commodities (less fuels) in the case of the demand charge and for anthracite coal or whatever fuel is used.

Much of the nonvariable cost in the capacity charge is for the fixed cost (depreciation) capacity. This is a sunk cost which will not grow over the life of the project. The entire capacity charge, however, is escalated as a function of the PPI for industrial commodities less fuel power and related products. Only the operating and maintenance (O&M) costs of heat plant operation will escalate over time due to labor and minor materials cost increases. Therefore, the Government may be at risk of excessive charges for capacity should industrial commodities inflation increase unexpectedly since the base against which the charge is escalated is the entire fixed cost of the plant plus O&M. This risk could be lowered easily by having a fixed demand charge essentially equal to depreciation plus profit, plus a nonfuel "commodity charge" covering nonfuel operating charges escalated by the industrial commodities.

Fuel price indices may not accurately represent the actual fuel costs incurred by the contractor. Recently, the PPI for coal (basis of charge to the Government) has been declining, yet the actual cost of the coal may include labor and handling charges (basis of increased charges to the contractor by coal suppliers), which have been increasing. Contract coal prices also are typically not reduced, according to one third-party contract. If the fuel charge/cost spread becomes unfavorable, the contractor risks financial failure and disruption of service. One cogeneration developer interviewed regards fuel cost variation as perhaps the greatest risk to the project economics. Unanticipated gas cost increases in the future are regarded by most third-party participants as an even greater risk than for coal. Contractors will likely want to be able to tie increases in their gas charges to indexes similar to those which suppliers are using to price the gas to them. The cost of gas purchased by contractors from their suppliers can be escalated by a variety of indices ranging from the percentage increase in the new contract price at the wellhead to

[6] 18 CFR, *Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policy Act of 1978 With Regard to Small Power Production and Generation*, Subpart B, "Qualifying Cogeneration and Small Power Production Facilities" (1 April 1987).

an average of gas cost increases for several pipeline suppliers. The latter would be a better index since it would avoid being tied to a single supplier's costs (which may reflect unusually rapid depletion of reserves or other unique factors). A more detailed discussion of these issues is available elsewhere.[7]

The Fort Drum contract specifies predicted technical characteristics of fuel, generation equipment, and so on. It does not specify the nature of fuel contracts, supply sources, and transportation modes. Although responsibility for fuel procurement rests with the contractor, the Army should ask potential contractors to represent in their bids:

- On what cost basis fuel is procured (type of index used to escalate price and timing of cost revisions).

- Whether alternative modes of transportation and supply sources, if feasible, have been provided for or are available.

Termination of Contract

The current contract form being used by the Army for third-party contracting (as exemplified by the contract and solicitation for bids examined provides for cancellation for the Government's convenience. Cancellation can occur before or after completion of the facilities to provide the heat supply. The procedures for cancellation are outlined in detail in both these two documents and include:

1. Notification to stop work and place no further orders or subcontracts.

2. Responsibility by the contractor to settle subcontracts and other liabilities.

3. Transfer of title to the Government for parts, supplies, and other material acquired for the work terminated.

4. Preservation and protection of property related to the contract.

5. Best efforts by the contractor to sell, as directed by the Government contracting officer, property described in 4 above.

6. Filing within 1 year of a final termination settlement proposal to the Government contracting officer.

The termination provisions of the contract form currently being used by Huntsville Division provide that:

1. In the case of contract termination prior to completion of facilities, a proposal for settlement will be submitted by the contractor covering reasonable costs associated with the contract "not to exceed the total contract price."

2. In the case of termination subsequent to completion of facilities, the basis for termination settlement will be the fair market value of the energy production facility.

[7] "Cogeneration: Negotiating a Long-Term Natural Gas Supply Contract," *Public Utilities Fortnightly* (May 26, 1988), pp 63-65.

Commenting on the legal adequacy of these termination provisions relative to usual terms of contract termination is beyond the scope of this study. However, in the event of contract termination, a contractor may incur damages of the following types:

1. The cost of equipment that cannot be recovered through resale.

2. Any reduction in cash flows due to the loss of this contract relative to the next one in which the contractor can reinvest the money (e.g., by having to settle for a less profitable project than the one entered into with the Government).

3. Costs of termination such as legal, appraisal, and dismantling fees.

Compensation for equipment and other expenses that cannot be recovered is standard procedure. It is recommended that "reasonable contract costs" be defined as expenses which cannot, by virtue of contract termination, be recovered. This should include the unrecoverable cost of equipment for cogeneration since loss of thermal energy sales disqualifies the contractor (under PURPA) for selling electricity to the local utility.

Loss of a project more profitable than could be obtained by redeploying project funds after termination grows in importance with the time that has passed since notice to proceed. The more time that passes before termination occurs, the more this situation becomes an issue. New contracts for thermal (and electrical energy if a cogeneration project) may be more difficult to obtain (either due to reduced demand, increased competition, or both), demanding lower pricing and cash flows. During the initial 2 years for construction, this is less likely to be an issue since the experienced contractor will have submitted a bid that anticipates near-term energy demand and pricing conditions.

This issue should be handled (as is typical practice) by allowing for appraisal of the facility's fair market value relative to its value were the third-party contract to continue. The appraiser should be an independent person with no interest in the project. Expenses (capital and operating) already recorded through charges to the Government would not be considered--only the value of future cash flows from the project as originally contracted (including electricity) in terms of:

1. Cash flow due to sale of thermal and electrical energy from that facility to other customers under market conditions prevailing at the time, or

2. The value of cash flows obtainable from another comparable facility assuming reimbursement for the net book value of assets from the Government facility (less salvage value).

Some of the concern that potential contractors have about the termination clause would likely be resolved if compensation for loss of value resulting from contract termination were allowed.

Basis for Bid Evaluation

The Government evaluates third-party contracts on the basis of their life-cycle costs compared with those of providing similar services through Government-owned and operated facilities. Life-cycle cost is the present value of constant dollar costs of thermal and electrical energy over the life of the contract

using a discount rate of 10 percent as specified in DEPPM 85-3. Energy costs are escalated by the latest Department of Energy (DOE) escalators by region as specified in 10 CFR 436, Subpart A.[8]

The discount rate of 10 percent (established by a DEPPM dated 12 August 1985) appears high as an inflation-adjusted rate for use in constant dollar cost projections. Current Government bond rates that reflect inflation expectations (which can be estimated at approximately 4 percent) are about 8 to 9 percent. Therefore, use of the 10 percent discount factor instead of a lower rate such as 5 percent (9 percent borrowing rates less 4 percent inflation) will tend to understate constant dollar life-cycle costs and allow higher annual charges by a third party.

The following example will illustrate this situation. Suppose that the Government has a choice of investing $25 million in an energy production facility versus buying energy from a third party who would build and operate an exact equivalent (annual operating and fuel costs) of the facility for 20 years. For the third-party contractor to be successful in his[*] bid to the Government, the life-cycle cost of his annual capacity charges would have to equal no more than $25 million (for this example, fuel and operating costs are assumed to be equal each year for either third-party or Government ownership and are ignored in this analysis).

To match the Government's life-cycle cost, the maximum annual capacity charges per year to the Government that the third party could bid under alternative discount rates are:

	Discount Rate (%)			
	10	8	6	5
Highest annual third-party charge which, over 20 years, would equal the Government's capital cost of $25 million ($M)	2.94	2.55	2.18	2.01

In effect, an arbitrarily high, inflation-adjusted discount rate such as 10 percent compared with an actual inflation-adjusted Government cost closer to 5 percent places too high a value than it should on annualizing an upfront capital expenditure for a heat plant over a longer period of time--essentially what third-party contracting does. Over 20 years, this results in $18.6 million in extra costs--nearly 75 percent of the initial capital cost of $25 million.

The standard of comparison for evaluating the life-cycle costs of third-party heat supply has been a Government-owned and -operated steam plant that does not cogenerate electricity. This is the least-cost option in most cases, as will be shown in Chapter 4.

The contract evaluation process considers contractor experience, financial backing, reputation, and other factors. However, to the extent that least cost is the primary selection factor for third-party contractors, the Government runs the risk of contracting with seemingly qualified contractors who are inexperienced in projects of similar scale and type. One way to avoid this outcome, as recommended by several developers interviewed, is to prequalify bidders based on actual experience in successfully

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[8] 10 CFR 436, *Federal Energy Management and Planning Programs*, Subpart A, "Methodology and Procedures for Life-Cycle Cost Analyses" (1 June 1987).

[*] The male pronoun is used for convenience in this report to imply both genders.

developing and operating comparable projects, and then solicit bids in a second step to be chosen based on least life-cycle costs.

The Government also requires submission of a financial plan for third-party projects but not necessarily the details of the bidding entities' financial organization. As noted earlier, the bidder usually will be a partnership. Where partnership financing of a third-party project is nearly (95 to 100 percent) all debt, there is a great risk that the third party (partnership) will run out of money and have to default to their lenders and potentially to the Government unless the partners add more capital.

Cash invested by partners usually is a sign of long-term commitment since they have actual money at risk and have simply been given a partnership interest in return for services. Therefore, it is recommended that bidders be required to disclose their capital structure (debt versus equity) and the amount of cash invested by each partner.

Summary of Contract Structure Review

A legal partnership of one or more private sector parties is the preferred form of organization to contract with the Government to supply heat and/or electrical energy. The partnership usually will consist of general and limited partners--the general having unlimited liability for the debt and other obligations of the partnership and the limited partner having liability equal to his initial investment in the partnership. This form of organization is preferred because, unlike a corporation, the partnership itself incurs no tax liability; the partners incur taxes on their portion of partnership cash profits directly on their own tax returns.

In addition to the services provided under the third-party heat supply contract with the Government, the private partnership may find it advantageous to cogenerate electricity along with steam and sell the electricity to the local utility for a negotiated payment rate per kilowatt hour (kWh) under the provisions of the Public Utilities Regulatory Policy Act (PURPA).[9] The validity of this contract with the utility is dependent (under PURPA) on continuing to have at least one thermal energy customer--in this case the Government. This makes the utility and Government contracts interdependent if cogeneration for sale to the utility improves the economics of the contract--a topic discussed in Chapter 4.

The capacity charge in the third-party contract is escalated by the PPI for industrial commodities (less fuels and power), but consists largely of depreciation of capital--a one-time expense. It is recommended that the pricing be changed to a fixed-capacity charge (unescalated), a nonfuel commodity charge escalated at the industrial PPI rate, and a fuel charge escalated by the appropriate PPI for fuel. This procedure will more closely align increases in charges to the Government with actual cost increases incurred by the contractor.

Settlement should be allowed the contractor in the event of contract termination for the convenience of the Government. The settlement should be based on fair market value of the project for the remaining term of the project, less the value of a comparable project (if it is lower than the current one) under market conditions at the time of termination, plus unrecoverable costs.

The current discount rate of 10 percent applied to inflation-adjusted dollar projections is too high and attaches too much value to deferral of energy production expenses for the Government. In effect, this

[9] PL 95-617, *Public Utilities Regulatory Policy Act (PURPA) of 1978* (9 November 1978), 92 Stat. 3117.

sets a higher annual threshold limit for third-party contract charges than is consistent with the Government's current cost of money.

Prequalification of bidders for third-party contracts based on successful completion and operation of similar projects will reduce the risk of defaulted projects. In addition, the investment of cash by partners in the project will provide a financial cushion against cost overruns, reduce the risk of defaulting on debt, and signify long-term commitment to completion and operation of the facility by the partnership.

3 PARTICIPANTS IN THIRD-PARTY CONTRACTING

Organizations Interviewed

To understand the objectives and prospects for participation in third-party contracts, USACERL interviewed leading firms already or likely to be involved in this business. These firms were identified from discussions with Huntsville Division, USACERL's own experience, and suggestions from the companies interviewed. The following companies were interviewed:

- CRS Capital--developer, engineer, and constructor
- Thermoelectron--developer and equipment supplier
- Dravo--Constructor
- Duke Power--Engineer and Designer (Fort Drum project)
- G.E. Credit--Financier
- Banker's Trust--Financier
- J.A. Jones Construction Company--Constructor (Fort Drum project)
- Niagara Mohawk--Utility (investor through a subsidiary in the Fort Drum project)
- First Boston--Financier (Fort Drum Project).

These interviews explored the following topics:

1. The extent of current participation in third-party contracting and reasons.
2. Financing structures used for third-party contracts and rates of return required by investors.
3. Types of debt financing used and why.
4. Profile of preferred third-party projects.
5. Risks to Government and third-party contractors in third-party contracting.
6. Suggested improvements to the third-party contracting process.
7. Future extent of involvement in third-party contracting.

The results of these interviews are summarized below along with USACERL's interpretation.

Types of Participants

Successful completion of a third-party contract for heat supply to a U.S. Government military installation involves a number of responsibilities. These range from an initial feasibility and engineering study to final design, construction, fuel procurement, and ongoing operation. As a result, several different parties typically are involved in a third-party contract, including:

- Developers
- Construction companies
- Financiers and lending institutions
- Equipment suppliers
- Fuel suppliers.

Some of these participants form and invest in a project financing organization--usually a joint venture partnership--to share the risks and rewards associated with a third-party contract. Others contract directly with the project financing organization on an as-needed basis to supply products and services procured with financing capital or energy sales revenues. Below are brief profiles of each participant.

Developers

Developers generally initiate a project by identifying the need or responding to a request for bid. The developer determines the feasibility of the project, including:

- Choice of technology for thermal or thermal and electrical output.
- Choice of fuels, availability, and price.
- Environmental and other permitting requirements and likelihood of meeting them.
- Availability of fuel and transportation for it.
- Land, utilities, and labor availability.
- Pricing of cogenerated electricity, if any, to the local power grid.
- Availability and cost of financing.
- Need for other partners.

Some developers assume primary responsibility for all aspects of a project whereas others work in partnership with other organizations whose responsibilities are defined. Because developers can initiate and control projects, some organizations such as Thermoelectron and CRSS (formerly CRS/Sirrine), which previously supplied only equipment or services to projects, have now become developers. CRSS also recently formed a separate subsidiary, CRS Capital, to develop and invest in all types of third-party energy projects (Government and commercial) as a natural extension of its work as a developer.

Not all developers perform the technical evaluations; some are local entrepreneurs. Developers who have successful experience in completing projects and who can evaluate the technical and economic feasibility of a project appear preferable to a local entrepreneur whose only incentive may be closing a contract and earning a development fee. An exception would be a developer who invests his own capital in the project and thus has an incentive (money at risk) to make the project successful.

Engineering and Construction Firms

Engineering and construction firms design and manage the construction of third-party heating plants. Some firms such as Fluor do engineering, design, and construction whereas others such as J.A. Jones and Blount, Inc. are general contractors hired to construct facilities. Duke Power, for example, designed and engineered the Fort Drum third-party project. Duke is a large publicly held electrical utility located in Charlotte, NC. This company was not new to engineering, however, having maintained a large internal engineering department for its own use in power plant design. Now that proceeds from the power plant construction are down, Duke is using its existing engineering capacity to earn revenues from services provided to outside customers. Either the engineering firm or the construction firm or both can be investors in a third-party project by providing cash directly and/or services at a reduced cost.

Financiers

Financiers provide the capital (cash) needed to cover all expenses of a project not covered by project revenues in the form of debt and partnership capital. Financiers of third-party projects fall into three categories that often overlap:

- Lenders of secured or unsecured debt
- Investors in project partnership capital
- Investment banks.

Lenders can be banks, insurance companies, or even individuals who lend money directly to the project or hold bonds issued by the project. Typically, during the construction phase of the project, floating rate bank debt is used and then recapitalized with fixed rate term debt upon completion of the construction for the term of the facility's operation or a shorter period such as 7 to 10 years. Floating rate debt carries an interest rate that rises or falls in direct relation to some benchmark interest rate such as the prime lending rate. This type of loan will typically be provided by a commercial bank. Permanent debt in the form of bonds and notes will be provided by institutional investors such as insurance companies.

A third-party project's debt financing is organized for the specific purposes of that project and it is not generally traded among investors as is the debt of public companies. This situation is not expected to affect the availability of funds for projects, however, since electric utilities, large domestic financial institutions, and foreign banks have substantial cash and a growing interest in investing in cogeneration projects.

Of possible interest to the DOD is the growing participation of foreign banks in the financing of cogeneration facilities. According to a knowledgeable cogeneration financier interviewed, these banks have been offering financing 2 to 3 percentage points below the interest rates quoted by U.S. banks for loans to fund third-party projects. According to this source, no cogeneration project in the United States has been financed by a domestic bank in the past 18 months. Other factors being equal, lower interest rates can reduce the cost of heat supply to the Government. The involvement of foreign bankers is not

necessarily a concern unless it becomes necessary to prevent access to information such as installation-specific energy consumption.

Nondebt financing of a third-party project or partnership capital typically comprises 20 to 30 percent. As noted, there are always general and, in most cases, also limited partners in a partnership. The general partner makes a small investment of cash (usually 5 to 10 percent of partnership capital) in the partnership and the limited partners contribute the rest. In return, most of the initial cash flow losses are allocated to the limited partners as a tax benefit and they receive a larger portion of initial cash profits until recovering all of their initial investment. After this, profits are split more equally among general and limited partners (40/60 percent or even 50/50). The actual profit-sharing formulas are negotiated for each project and vary widely.

If, as is believed to be the case, many third-party projects are cogenerated facilities, an electrical utility may not, under 18 CFR 292, Subpart B, own more than 50 percent of the equity in a cogeneration facility. Other ownership and profit distribution restrictions are likely to be project-specific and reflect protective measures desired by debt holders or lenders.

Investment banks help to obtain both debt and partnership capital financing for third-party projects by advising how best to structure the relative percentages, terms of debt, and partnership capital, and by contacting potential investors to obtain funds. Underwriters include investment bankers such as First Boston, Goldman Sachs, Drexel Burnham & Lambert, and many others. Some underwriters also will invest in the equity of a project and become principals as well as underwriters.

Investment bankers are typically paid fees for financial advice and obtaining capital for a project. If debt financing must be committed before contract award, as apparently required by the Navy and Air Force (based on interviews), then additional financing commitment fees also will be incurred by the project owners and passed on as a project cost. These fees can be substantial, ranging from 0.5 to 1 percent of a project's financing requirements.

Equipment and Fuel Suppliers

Equipment and fuel suppliers provide needed capital equipment, fuel, and some design expertise. They typically play a less active role in the project than the developers and engineering/construction firms. They do provide specifications for equipment and fuel as well as price quotes early in project development for bid preparation.

Objectives and Criteria for Participation in Third-Party Contracting With the U.S. Military

With one exception, all of the private sector organizations interviewed expressed an interest in third-party contracting. All of these organizations expressed concern, however, at the cost and duration of contracting processes currently being used for third-party projects. The decision to participate in a third-party contract is judged on a project-by-project basis by all companies interviewed. Nearly all indicated that the capital cost of the project should be more than $10 million in view of the substantial cost (around $500K in the opinion of most) for bid preparation. They also noted that the amount of PURPA payments that private contractors can receive by cogenerating and selling electricity to the local power grid is a key factor in deciding to bid. (Chapter 4 examines this issue in more detail.) Although most companies complimented the Army's third-party contracting expertise at Huntsville, they indicated that more streamlined bidding procedures to prequalify bidders, allow greater flexibility in fuel choice (now allowed, although local political pressures may still affect this--e.g., in support of coal companies or wood cutters),

and greater confidence that a proposed project will be economically feasible for third-party versus Government ownership are needed to increase their willingness to participate in future bids.

Huntsville Division is currently conducting feasibility studies before soliciting third-party bids to confirm the potential for third-party feasibility. This task is done by analyzing a project's economics to ensure that it can be profitable to a third party while providing thermal energy at costs comparable to Government ownership. Perhaps better communication of this process to potential contractors in bid solicitations could help to encourage participation.

Participants in third-party contracting have four broad objectives:

1. Expanding their current business.

2. Controlling project development.

3. Reducing risks associated with third-party projects.

4. Earning an acceptable return on funds invested in projects.

All participants in third-party contracting seek to expand the market for the products or services they provide. These include engineering services, financing, construction services, and equipment sales. In some cases, suppliers become partners, selling equipment to the project at a lower price and trading some current profit on what they supply in return for a share of the future profits.

The primary movers behind third-party contracting are developers, engineering and construction companies, and some financiers--especially those targeting the industrial credit and leasing market. They seek to identify and develop, ideally on a noncompetitive basis, large projects for heat supply and cogeneration. Since Government third-party projects have no unique technologies, they must be bid competitively under existing procurement regulations according to the Huntsville Division staff interviewed. Since they incur the risk of not winning the project bid, developers want to reduce the time and cost of bidding (believed to result in part from Government procurement regulations), changing project specifications and uncertainty over whether the project will be awarded to any third-party contractor--that is, whether a third party can design a facility with lower life-cycle costs than the Government could do. In fact, a knowledgeable contractor should know whether a steam plant or cogeneration plant will likely provide steam to the Government at lower costs based on Government requirements and (as pointed out in Chapter 4) the payment for cogenerated electricity he also could receive.

Failure to win the project after preparing a complete bid at high cost is one risk developers believe could be reduced to the benefit of the Government by prequalification of bidders. Potential bidders would submit complete bid packages only after being screened to determine their prior success in developing and operating similar projects. This practice apparently has been used in some, but not all, third-party project soliciting.

All companies interviewed are concerned about the "termination for convenience of the Government" clause in the third-party contract. Although the clause provides for payment of the facility's fair market value, this settlement may not be enough to liquidate the debt on the project and/or leave investors with a poor return on equity. Contractors (or potential ones) believe changes in annual appropriations for which continuance cannot be guaranteed could trigger the cancellation clause.

Because these risks are perceived to be associated uniquely with third-party contracting, some developers and investors claim they require a higher minimum return on equity than for an otherwise

similar project, thus increasing the cost and/or reducing the pool of bids. One organization indicated that it would add 10 percentage points to its normal required rate of return (typically about 20 percent) because of these risks. In the author's opinion, the more predictable thermal requirements of Government facilities compared with an industrial plant offset these risks somewhat and make this issue insignificant, assuming that some changes, such as provision for independent appraisal (see Chapter 2) are allowed in contract termination.

Finally, participants in third-party contracting who invest capital (equity) in project partnerships generally seek a return on this capital in current dollars of approximately 20 percent. While some interviewees specified returns above and below this figure, 20 percent is an average and is typical of projects financed with 70 to 80 percent debt (as a percentage of total capital required), as is the case with third-party contracts. In fact, debt financing is the main way contractors achieve this return on equity; interest payments on debt are tax-deductible whereas payments to investors are not, thus greatly reducing the after-tax cost of debt relative to equity. As long as project returns on total capital exceed the after-tax cost of debt, then profits as a percentage of investor capital increase.

Table 1 shows the relationship between minimum debt and equity costs after taxes as a function of the relative percentage of debt and equity in the capital structure. It shows that, as the percentage of project capital financed with debt rises, the average cost of project capital (weighted by the relative percentages of debt and equity) declines. Note that the cost of debt and equity each rise as the percentage of debt financing increases; this is to compensate both lenders and investors for the increased risk of bankruptcy at higher debt levels.[10]

[10] For a further explanation of this relationship and the rationale for the formula in Table 1 by which minimum returns required by equity investors are adjusted for the level of debt in capital, see T.E. Copeland and J.F. Weston, ***Financial Theory and Corporate Policy*** (Addison Wesley, 1979), p 282.

Table 1

Impact of Increasing Leverage (Debt as % of total Capital) on the Weighted Average Cost of Total Capital (Nominal Dollars)*

	Percentage of Projected Capital Financed With:	Percentage Cost After Taxes (@ 34%) of:		Average Weighted Cost of:
(1) Debt (%)	(2) Equity (%)	(3) Debt	(4) Equity (%)	(5) Total Capital (%)
0	100	0	14.00	14.00
10	90	6.6	14.29	13.52
20	80	6.8	14.61	13.05
30	70	6.8	15.05	12.58
40	60	7.0	15.49	12.09
50	50	7.4	15.84	11.62
60	40	7.6	16.46	11.14
70	30	7.9	17.08	10.65
80	20	7.9	19.28	10.18

* Average cost of capital (column 5) = after-tax cost of debt (column 3) x percent debt financing (column 1) + cost of equity (column 4) x percent equity financing (column 2). Debt costs are for illustration only, but are judged to approximate the change in interest rates on a 25-year bond that could be expected for increasing leverage. Actual financing terms vary widely, with rates typically higher with longer terms of financing and levels of risk. The cost of equity (with debt) = cost of equity (no debt) + (1 - tax rate) (cost of equity without debt - cost of debt) (% debt/% equity).

Debt financing in excess of 80 percent of the required capital is not prudent for the following reasons:

1. At 80 percent debt financing, the ratio of pretax operating cash margin to the debt interest and principal payment is approximately 1.2 for a third-party steam plant (see Appendix B). Debt financing greater than 80 percent of project capital would reduce this ratio below 1.2--a minimum prudent level in the authors' experience.

2. A significant nondebt capital contribution is needed so that project partners have funds at risk to ensure their commitment to successful contract performance.

Profile of an Ideal Third-Party Project

When asked what the characteristics of an ideal third-party heat supply project for the military would be, interviewees responded as follows:

1. High avoided cost payments for electricity cogenerated with steam or hot water (probably greater than 6¢/kWh).

2. Large (e.g., more than 25 MBtu/hr) steam demands to meet minimum capital cost criteria.

3. Capital cost of at least $10 million to justify the cost of bidding.

4. Need for boiler replacement or expansion of existing heat plant.

5. Bituminous coal (for plants with more than approximately 500 MBtu/hr capacity) or natural gas fuel.

6. Adequate land and utilities to support a heat plant with cogeneration either supplied by the Government or available adjacent to the installation.

Most interviewees stressed that while all of these characteristics would be ideal, the economics of specific projects can be good even if not all of the above factors are favorable. Most stressed the avoided cost payments for electricity to cogenerators under PURPA as being most important to project economics. This is because avoided cost payments for electricity that exceed incremental costs (including profit) of adding equipment and fuel purchases for cogeneration will allow the third-party contractor to apply this extra revenue to reducing the cost of thermal energy to the Government (see Chapter 4).

It is estimated that gas boilers for steam-only plants are less costly (life-cycle cost) per MBtu/per hour of capacity than stoker-fired coal boilers of all sizes. Gas turbine cogeneration is less costly than coal steam turbines on the same basis for steam capacity up to about 300 MBtu/hr. A minimum capital cost of $10 million would correspond approximately to a gas boiler (steam only) of 20 MBtu/hr. The steam capacity of a gas turbine cogeneration system at this capital cost will depend on the ratio of steam to electric energy (which by PURPA must be no less than 5 percent) and the level of PURPA-avoided cost payments. In the authors' judgment, it is likely that thermal requirements as small as 25 MBtu/hr capacity could be satisfied by a $10 million gas turbine cogeneration facility, although this will depend on specified project characteristics (heat rate of the technology, avoided cost payments, and equipment capital costs).

Suggested Improvements to the Third-Party Contracting Program

Interview respondents suggested several possible improvements to the third-party contracting program. These suggestions are summarized below.

1. The Government should perform a preliminary feasibility study for a potential project before releasing it for bid to increase the likelihood that it will, in fact, be awarded as a third-party project based on a reasonable expectation of acceptable profit to the third-party and life-cycle energy costs at or lower than those that would be incurred by the Government.

2. Prequalify bidders prior to soliciting complete design and cost bid submissions.

3. Establish a group within the Government or in each military branch specializing in procurement of third-party financed services and maintaining expertise in evaluating private sector financing techniques.

4. Remove fuel use restrictions on third-party contracts (already done as noted above).

5. Target the bid evaluation time to be no more than 3 to 6 months to reduce risks of unanticipated increases in financing costs (actual times apparently have been longer due to detailed and repeated requests for cost data from the contractor selected in the first round of bidding).

6. Allow qualified bidders to bid subject to obtaining financing to avoid having to pay financing commitment fees (qualified bidders who have previously secured financing, and developed and completed successful projects should be able to secure financing--especially if they have a firm contract with the Government).

7. Ensure that site acreage, water, and transportation access are adequate for a cogeneration facility if only Government land is available--on average, they must be larger than for a steam plant.

Because third-party projects involve project-specific financing, additional legal protections and documentation are typically required. These requirements can be complex--especially relative to normal Government procurement of services and equipment. Most private sector participants believe it is necessary for Government procurement officers to develop and maintain continuity of understanding about these requirements to reduce the time and effort involved in completing third-party projects.

Risk

Interviewees who now participate in third-party contracting believe the principal risks to the Government in third-party contracting are:

1. Selection of low-cost, but inexperienced and under-capitalized, contractors who default.

2. Project delays preventing ontime delivery of hot water, disrupting installation missions.

3. Unanticipated fuel cost increases and/or disruption of supply due to a contractor's failure to diversify supply sources--especially for gas.

Risks to the third-party contractors were identified as:

1. Cost overruns (especially for fuel) that cannot be recovered with change orders or escalation clauses;

2. High expense of proposal preparation relative to risk of not winning (large number of bidders) and risk of the project not being awarded to any third-party contractor;

3. Risk of approval delays increasing exposure to unanticipated cost increases;

4. Inability to obtain environmental and siting permits;

5. Termination for convenience of the Government resulting from changes in missions or annual appropriations.

Few of the above risks are unique to third-party contracting. Normal procurement of capital equipment can experience cost overruns, default of suppliers, and similar problems. Selection of inexperienced and under-capitalized contractors who default is the biggest risk to the Government due to the requirement for long-term operating responsibility. Cost of bid preparation relative to the probability of success, fuel cost escalation that cannot be passed on, termination risk, and the cost risks of delayed project approval due to Congressional review are the greatest risks to the third-party contractor. As noted above, prequalification, based on experience, of third-party bidders, and project screening and feasibility analysis by the Government should reduce these risks to the Government and private contractors, respectively.

4 FINANCIAL ANALYSIS OF THIRD-PARTY CONTRACTS

The purpose of this analysis is to determine what factors can make the life-cycle costs of thermal energy supplied by a third party less than those of a Government-owned and -operated facility.

Assumptions

General assumptions for the analysis are:

1. There are no significant differences in operating efficiencies or the availability of technology for the Government versus a third-party contractor.

2. Plants will be built to meet maximum required thermal demand defined as MBtu/hr.

3. The new tax law applies to all projects; the 10 percent investment tax credit is repealed; energy tax credits (ETCs) remain available only for biomass and geothermal projects through 1987 and 1988, respectively; depreciation of cogeneration equipment now takes place over 15 to 20 years rather than 5 years; there is a 37% Federal and State tax rate on project income (to the partners in the case of a partnership).

4. A military-owned facility can consume cogenerated electricity for its own load, but cannot sell electricity back to the local utility grid.

5. All Army and third-party contractor facilities will use the most economical fuel available.

Methodology

To analyze these issues, a financial model was constructed; the structure is summarized in Figures 1 and 2. Assumptions for the model include:

1. A 25-year total contract or life-cycle cost period (2 years to construct and 23 years of operation).

2. Partnership business structure for the third-party contractor.

3. Debt financing for 80 percent of the project cash investment; the rest is partnership capital.

4. Interest rate of 11 percent on debt.

5. Minimum return on nondebt capital (after tax of 15 percent).

6. All projections in constant (inflation-adjusted) 1988 dollars.

7. Fuel cost assumptions and escalation rates for fuel (DOE projections in 10 CFR 436, Subpart A, January 1987) and capacity charges (Data Resources, Inc., Long Term Forecast of the Non Fuel Industrial Producer Price Index) in each case are shown in Appendices A through F.

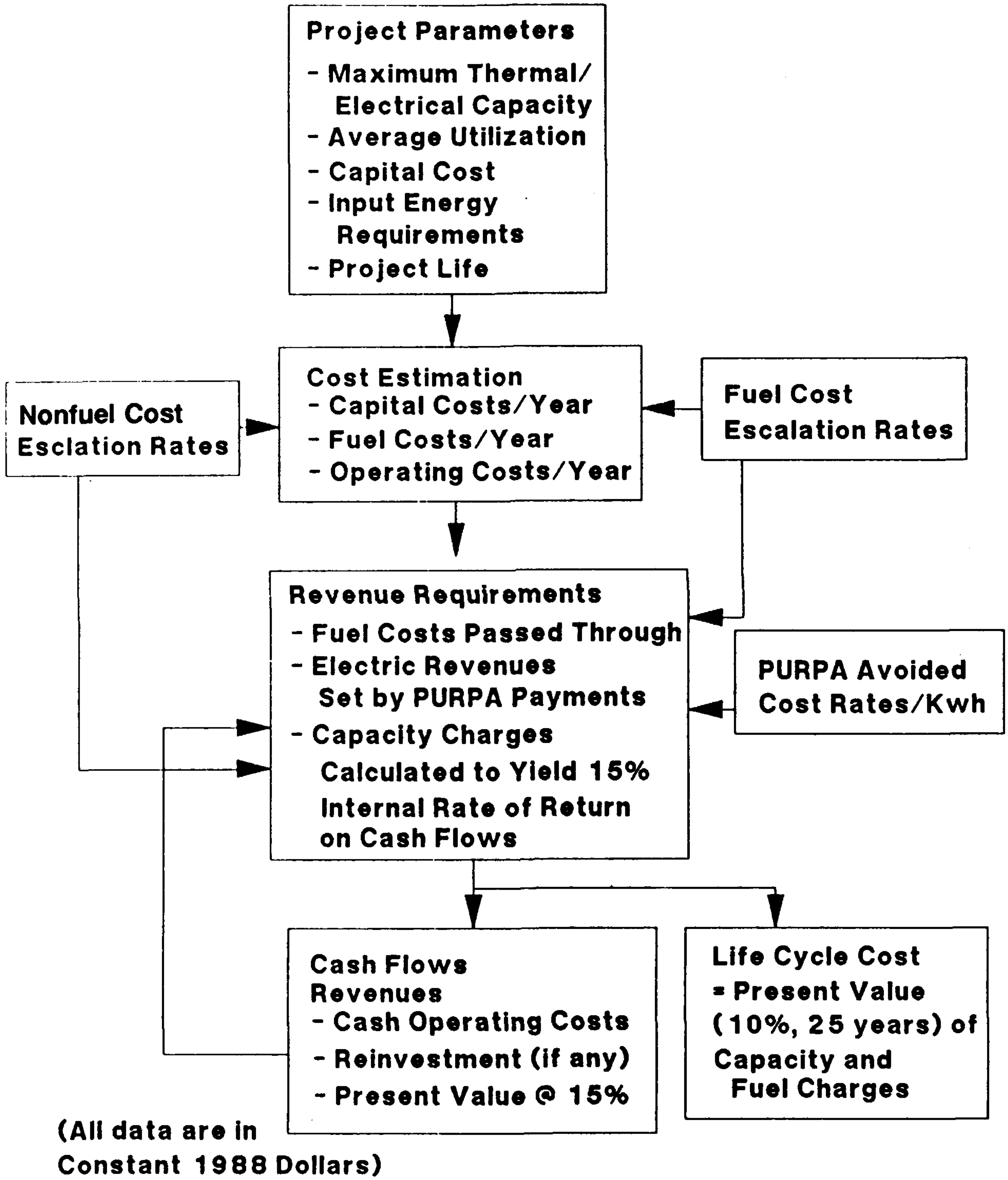

Figure 1. Structure of financial model for third-party heat supply analysis.

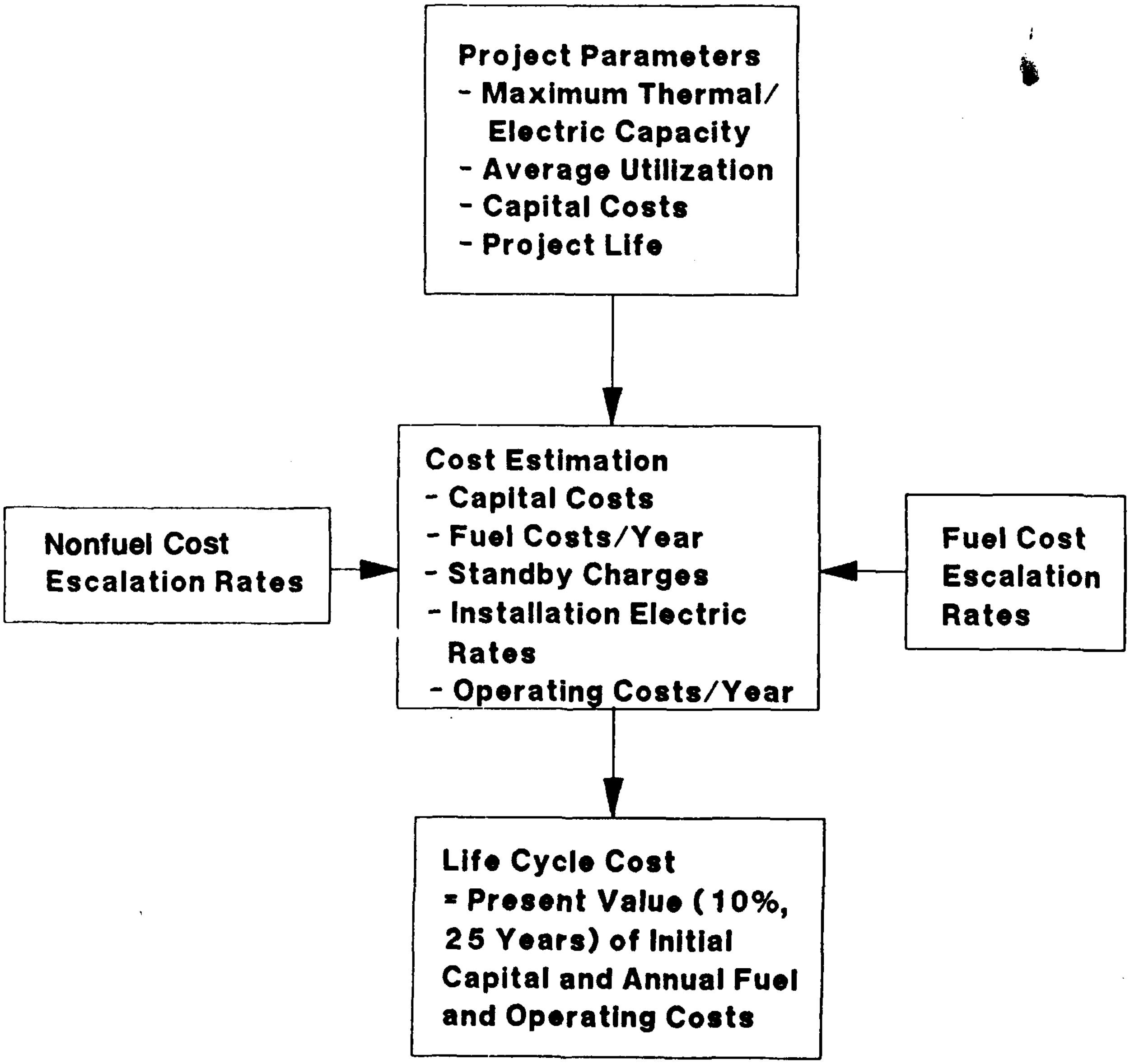

Figure 2. Structure of financial model for Govcernment-owned amd -operated heat/electrical supply.

The following six analysis sets were prepared:

1. Annual costs (millions of dollars/year)/MBtus/hr of capacity (assuming average utilization of 37 percent) for Government-owned and -operated coal- and gas-fired boilers at 100, 260, 500 MBtu/hour to identify least-cost fuel at 260 MBtu/hr which is both an average size (thermal energy consumption) base and the size of Fort Drum's third-party contractual requirement--a project for which detailed cost and operating information is available.

2. Annual costs per maximum hourly capacity for thermal energy (assuming same average utilization as in 1 above) from cogeneration facilities receiving 4¢/kWh PURPA payments for gas turbine and coal steam turbine systems at 100, 260, and 500 MBtu/hr rated capacity.

3. Relative life-cycle costs of third-party and Government-owned gas-fired boilers each with capacity of 260 MBtu/hr and 37 percent average utilization.

4. Life-cycle cost of a third-party gas turbine cogeneration plant supplying up to 260 MBtu/hr of steam and receiving 2, 4, and 7¢/kWh PURPA payments from the local utility for electricity.

5. Life-cycle costs of a third-party cogeneration plant as in case 4, but selling the cogenerated electricity only to the installation for a rate per kilowatt-hour typical for large industrial electric customers.

6. A comparison of the life-cycle costs of gas turbine cogeneration facilities (same size as in 4 and 5 above) for DOD and third-party ownership with electrical output used only by the installation in the case of DoD ownership and sale of electric output by third-party to the base and local utility.

How Cogeneration Can Affect Life-Cycle Heat Supply Costs for Third-Party Contractors Vs. the Government

A third-party contractor could generate additional revenues from the sale of electricity cogenerated with steam, which could allow it to sell thermal energy to the Government at lower life-cycle cost than for generating steam from a Government-owned and -operated plant, and still earn an acceptable return on capital.

For this to happen, the revenues to the third-party contractor from the sale of electricity must exceed the incremental capital and operating costs (fuel and nonfuel) incurred to generate the electricity. Revenues for electricity to a third party are derived from qualification as a cogenerator of electricity under PURPA and from avoided cost payments (using¢/kWh) established or negotiated with the utility in whose service territory the plant will be located. The payments will include that for avoided energy costs by the utility and may or may not include money for avoided capacity. Generally, if that utility and the others in its power pool have enough capacity, they will not make capacity payments, thus reducing the overall rate per kilowatt hour. Even when they do, these payments often are based on the amount of actual generation by the third party during periods of peak demand on the utility's system. These, for example, could be late afternoon and early evening hours during the summer, although the actual peak demand periods vary widely by utility.

Payments for avoided energy costs also vary in many cases by time of day and season, as the utility will be avoiding different types of fuels depending on the percentage use of its generating capacity. Calculation of actual avoided costs and electricity revenues depends, therefore, on the location of a specific project and on the terms of avoided cost payments. Both are specific to a particular project and must be evaluated on a case-by-case basis; however, it is possible to analyze the cogeneration configuration (fuel, technology, etc.) needed to make a third-party project economically feasible given an average kilowatt hour avoided cost payment. This analysis can be used as a first screen to eliminate many regions of the country where avoided cost payments will not be at least as high as the average level.

Currently, there is a trend toward competitive bidding solicitation by utilities for cogenerated and independent power production. If fully implemented, competitive bidding may relieve utilities of their obligation under PURPA to buy all cogenerated power offered (including third-party contractors). The exact outcome of this trend is unclear at this time.[11] The implications for third-party contractors may not be as negative as it would first appear, for two reasons:

1. PURPA-avoided cost payments to cogenerators have already been lowered in many regions to unattractive (below 6¢/kWh) levels for making third-party projects profitable.

2. It may be more advantageous in some cases for third-party contractors to supply electricity to the installation and be paid the rate for this power that the installation is now paying the local utility--typically (5 to 7¢/kWh) on average.

To cogenerate electricity, additional capital and operating costs are incurred for generating equipment compared to a steam-only plant. A 260-MBtu/hr coal-based steam cycle cogenerating facility has capital costs nearly four times those of a coal-based steam boiler but provides additional revenues from electricity. Assumptions underlying these costs are discussed in the next section.

However, a gas turbine cogeneration facility has capital costs only twice those of a coal boiler steam plant, but substantially higher fuel costs. In this case, that portion of the energy attributable to steam supplied to the Government is passed through as a fuel charge. The portion attributable to electrical power may not be fully covered by the avoided cost payments for electricity, potentially making the project uneconomical. Some utilities base their avoided cost payments on a coal-fired generating facility, which would not cover the cost of gas energy for generating electricity.

Therefore, a gas turbine cogeneration facility with its lower capital costs which can obtain favorable avoided cost rates for electricity may be the only way for a third-party to provide steam at a lower life-cycle cost than a Government steam-only plant by allowing a reduction in thermal energy costs from profits on sales of electricity. However, if the Government were to build its own gas turbine cogeneration plant, its cost would be lower than for a third party (no taxes or profit required). If, in addition, it could avoid purchase (through cogeneration) of electricity at rates higher than PURPA payments available to a third party, it could subsidize its own thermal energy costs, potentially making Government-owned and

[11] "Competitive Bidding in Electric Power Procurement: A Survey of State Action," *Public Utilities Fortnightly* (March 17, 1988), pp 41-45.

-operated cogeneration plants the least-cost source of thermal energy. The financial analyses for this study considered these factors; the results are discussed under Discussion of Results below.

Capital Cost Assumptions

The capital cost estimates prepared for the example cogeneration project were developed using the standard engineering factored cost approach and were cross-checked extensively with a variety of primary and secondary data for internal consistency. Cogeneration projects can vary significantly from one to another in terms of design and, therefore, cost. The emphasis in developing these cost estimates was to arrive at a set of costs which is internally consistent. As a result, the relative comparisons have maximum accuracy.

A variety of data sources was used in developing the costs. Many of the design and cost equations were based on the Industrial Cogeneration Optimization Program (ICOP), study done for DOE[12] in which detailed engineering designs and costs were prepared for 10 prototype cogeneration systems. The project included Gibbs and Hill and Westinghouse, and the cost data prepared are an acknowledged reference in the field.

Specific data sources used for the individual cost estimates included:

- The coal boilers are based on ICOP data, updated and cross-checked with USACERL.
- The gas/oil boilers are based on ICOP data, updated and cross-checked with CERL and vendor quotes.
- The steam turbine cogeneration system is based on ICOP data, updated and cross-checked with Fort Drum data, figures from a private 72-MW coal-fired cogeneration system, and vendor quotes.
- The gas turbine cogeneration system is based on a vendor system quote and cross-checked with ICOP and four private gas turbine cogeneration systems.

In each case, the data have been cross-checked extensively to ensure consistency.

Cogeneration systems can be optimized in a variety of ways. For any given thermal load, a variety of different system configurations and sizes can be chosen. Each will have different capital and life-cycle costs. With regard to the 260 MBtu/hr system analyzed by USACERL:

1. It was estimated that the cost of a 260-MBtu/hr coal-fired boiler is $25 million, including the scrubber ($20 million without the scrubber). This is based on:

- Maximum thermal load to base of 260 MBtu/hr
- Stoker coal firing
- 250 psig saturated steam.

[12] *Industrial Cogeneration Optimization Program*, DOE/CS/05310-01 (Department of Energy, January 1980).

2. In comparison, USACERL data estimated $19.6 million for a 250 MBtu/hr coal stoker without a scrubber.

3. Similarly, a capital investment of $11.5 million was estimated for a 260-MBtu/hr gas/oil boiler; USACERL indicates $10.8 million.

4. For a coal-based cogeneration system supplying 260 MBtu/hr thermal (maximum), the capital investment was estimated at $95 million.

5. The steam turbine-based system is based on the following:

- Maximum thermal load to base of 260 MBtu/hr
- 475,000 lb/hr pulverized coal boiler, 532 MBtu/hr
- 1500 psig/950 °F steam (based on Fort Drum)
- 59-MW steam turbine; single extraction point at 170 psig; 2.5 in. Hg condenser
- Normal load is 106,800 lb/hr extraction steam to thermal load (base); 82,700 lb/hr extraction steam to deaerator; 285,500 lb/hr steam to condenser.

6. For comparison, this matches the capability of the Fort Drum system, which was financed at $93 million.

Regarding the difference in capital investment for the boiler component of the cogeneration system compared with the 250-psig saturated steam boiler, cost variations were approximately as follows:

- Cost factor of about 1.65 due to size difference--532 MBtu vs. 260 MBtu
- Cost factor of about 1.5 due to pressure difference--1500 psig vs. 250 psig
- Cost factor of about 1.25 due to technology differences (i.e., Stoker vs. pulverized fuel, degree of shop fabrication, saturated steam vs. superheated steam, addition of air preheater on larger unit).

These three factors accounted for a difference of about a factor of 3 in the cost of the boiler portion of the cogeneration system vs. the stand-alone boiler. The rest of the difference in system cost is for the steam turbine and electrical components.

Discussion of Results

Case 1: Relative Costs of Thermal Energy by Fuel Type and Boiler Size

The life-cycle costs were projected for steam boilers of 100, 260, and 500 Mbtu/hr maximum rated capacity using the financial model described earlier. It was assumed that these boilers would be Government-owned since that is likely to be the lowest cost option by excluding the taxes and return on capital that a third-party must earn. The assumption of 37 percent average use (MBtu/hr) of maximum rated capacity reflects the characteristics of energy consumption in the Fort Drum project.

As shown in Figure 3, gas-fired boilers are likely to be lower cost (total life-cycle costs over 25 years scaled by boiler size) than coal up to very large size boilers. Since coal fuel costs per Btu are lower, capital costs are higher than for gas, higher average levels of utilization would likely lower the minimum size boiler at which coal would be competitive with gas. However, at a 260-MBtu/hr capacity, gas is likely to be the most economical (compared with coal) unless very high levels of usage are assumed (unrealistic in the authors' opinion except for purely industrial operations).

Case 2: Relative Costs of Thermal Energy Cogenerated With Electricity by Fuel Type and Thermal Capacity

Figure 4 shows the life-cycle cost of cogeneration by fuel type and thermal capacity (over 25 years at a 10 percent discount rate) scaled by maximum thermal capacity. USACERL assumed a payment under PURPA for average generated electricity of 4¢/kWh. The economies for each level of capacity and fuel type is indicated in Tables 2 through 5. Again, the average usage level of thermal rated capacity is 37 percent.

Up to about 400 MBtu/hr, gas again is more economical than coal due to !ower capital costs. At larger sizes, the lower fuel costs and economies of scale for coal plants produce lower economics. As in the case of steam boilers, higher levels of thermal usage will tend to lower the minimum scale of thermal capacity for economical use of coal. Avoided cost payments higher than $0.04/kWh will tend to lower life-cycle costs as noted below and thus the cost of cogeneration cannot be considered independently of the value of the electricity. This electricity can be valued as noted below using either the avoided cost payment per kilowatt hour available from the local utility or the value of electricity sold to the installation by the local utility—in which case externally supplied power would be replaced by that cogenerated.

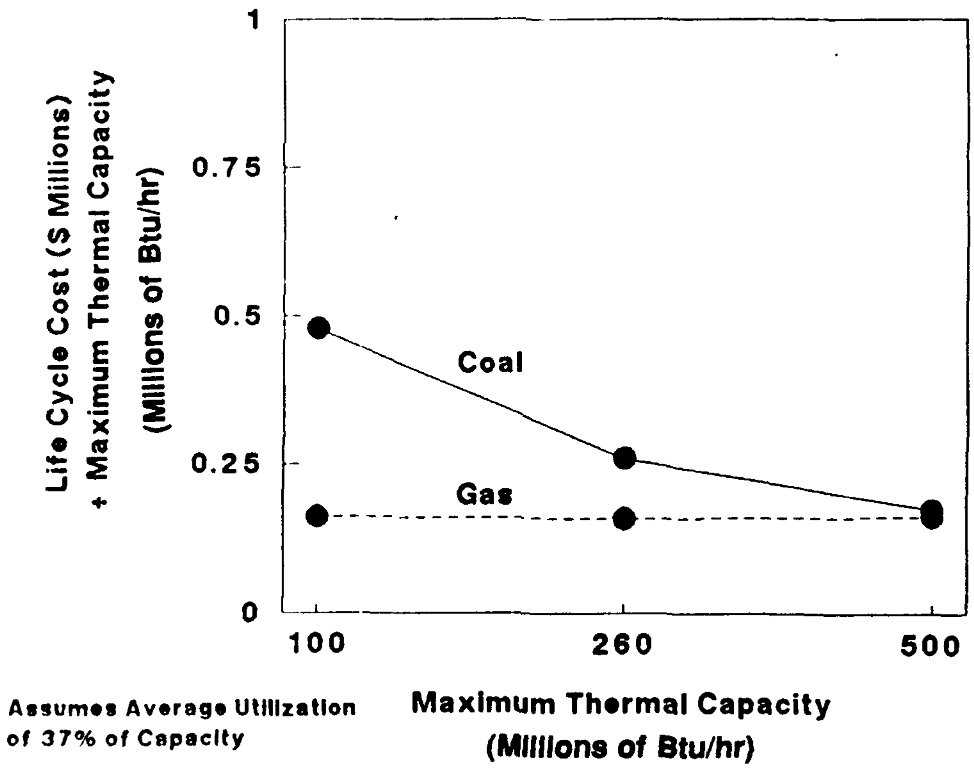

Figure 3. Relative costs of Government-owned and -operated boilers as a function of scale.

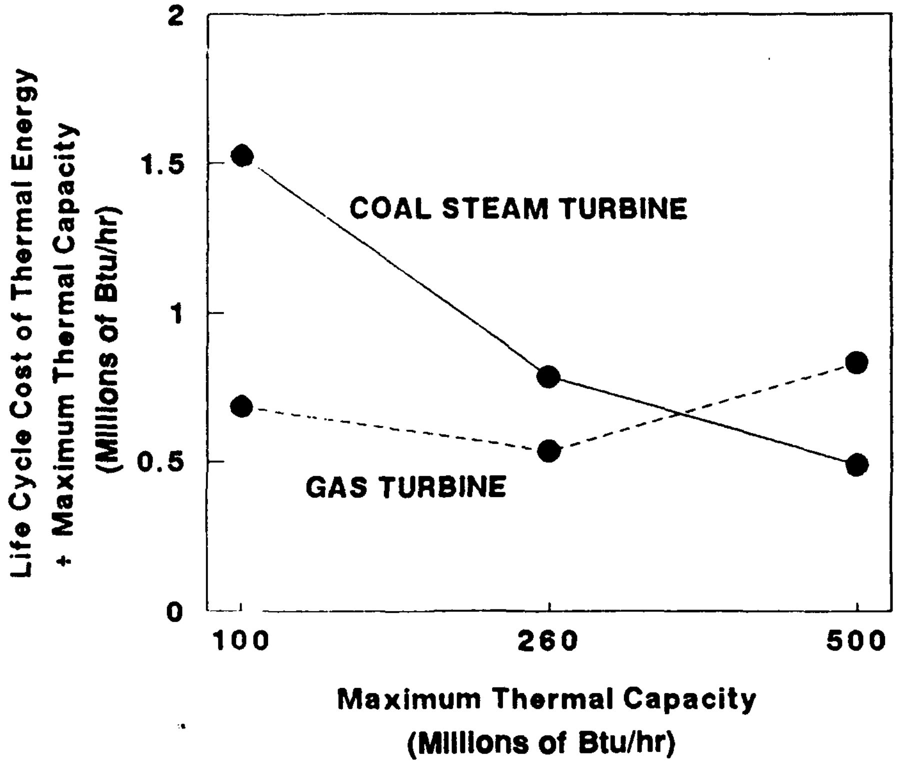

Figure 4. Relative costs of thermal energy from third-party cogeneration plants (@ 4¢/kWh PURPA payment).

Case 3: Life-Cycle Cost of Thermal Energy From Government-Owned and Third-Party Boilers

For a 260 MBtu/hr gas-fired boiler, the life-cycle costs of steam to the Government were projected for Government and third-party ownership. Figure 5 shows that third-party costs would be 20 percent more than Government ownership, due partly to taxes and partly to required profit targets.

Case 4: Life-Cycle Cost of Thermal Energy Cogenerated by a Third Party Along With Electricity

Assuming that gas turbine cogeneration is most economical at a maximum thermal capacity of 260 MBtu/hr, USACERL projected the life-cycle cost of thermal energy sold to the Government by a third party who also sells electricity to the local utility. A net generation of 58 MW and 95 percent availability were assumed for both thermal and electrical energy. Thermal usage on average is 37 percent of the maximum rated capacity and all electricity generated (95 percent availability) is sold to the local utility under PURPA. In this case, the third-party contractor must have sufficient profit (over operating and capital costs, including profit) to be able to reduce his demand charge for thermal energy enough to achieve a life-cycle cost for thermal energy (fuel and demand charge) equal to a Government-owned and -operated gas-fired boiler. USACERL's financial model indicates that this PURPA payment must, on average be at least 5.8¢/kWh as shown in Figure 6.

Case 5: Government-Owned and -Operated Cogeneration

This case analyzed the life-cycle cost to the Government of owning and operating its own gas turbine cogeneration facility scaled to provide up to 260 MBtu/hr of thermal energy and net generation capacity of up to 40 MW. Data from USACERL were used to estimate the peak electrical capacity required for a facility with peak thermal requirements of 260 MBtu/hr to be 40 MW and average consumption per month of 14.3 million kWh. The capital cost for this facility was estimated to be $25.8 million and fuel costs 38 percent of those in the preceding case. In addition, the installation likely would incur standby

Table 2

Economics for a Coal-Fired Stand-Alone Boiler

Peak Thermal Capacity (MBtu/hr)	Average Thermal Load (MBtu/hr)	Capital Investment ($M)	Operating Costs
100	37.4	12.3	Maintenance & Labor = $0.60M/yr Fuel = (0.371 x 10^6 MBtu/yr) x fuel price ($/MBtu) Scrubber = $0.6M/yr
260	97.3	25.0	Maintenance & Labor = $0.93M/yr Fuel = (0.963 x 10^6 MBtu/yr) x fuel price ($/MBtu) Scrubber = $1.2M/yr
500	187.1	41.1	Maintenance & Labor = $0.36M/yr Fuel = (1.854 x 10^6 MBtu/yr) x fuel price ($/MBtu) Scrubber = 2.4M/yr

Table 3

Economics for a Gas-Fired Stand-Alone Boiler

Peak Thermal Capacity (MBtu/hr)	Average Thermal Load (MBtu/hr)	Capital Investment ($M)	Operating Costs
100	37.4	2.7	Maintenance & Labor = $0.33M/yr Fuel = (0.389 x 10^6 MBtu/yr) x fuel price ($/MBtu)
260	97.3	11.5	Maintenance & Labor = $0.54M/yr Fuel = (0.963 x 10^6 MBtu/yr) x fuel price ($/MBtu)
500	187.1	19.4	Maintenance & Labor = $0.79/yr Fuel = (1.946 x 10^6 MBtu/yr) x fuel price ($/MBtu)

Table 4

Economics for Steam Turbine Cogeneration Systems

Maximum Thermal Capacity (MBtu/hr)	Average Thermal Load (MBtu/hr)	Average Generation Capacity (MW)	Net Generation (MW)	Capital Investment ($M)	Operating Costs/yr
100	37.4	19	16.8	44.2	Maintenance & Labor = $1.46M/yr Fuel Cost = ($2.03 \times 10^6$ MBtu/yr) x fuel price ($/MBtu) Scrubber = $2.53M
260	97.2	49	43.6	95.0	Maintenance & Labor = $2.75M/yr Fuel Costs = ($5.26 \times 10^6$ MBtu/yr) x fuel price ($/MBtu) Scrubber = $6.48M
500	187.0	94	84.0	145.4	Maintenance & Labor = $4.11M/yr Fuel Cost = (10.13x106 MBtu/yr) x fuel price ($/MBtu) Scrubber = $12.7M

Table 5

Economics for Gas Turbine Cogeneration Systems

Maximum Thermal Capacity (MBtu/hr)	Average Thermal Load (MBtu/hr)	Generation Capacity (MW)	Average Net Generation (MW)	Capital Investment ($M)	Operating Costs/yr
100	37.4	36	30	24.1	Maintenance & Labor = $1.01M/yr Fuel Cost = ($3.28 \times 10^6$ MBtu/yr) x fuel price ($/MBtu)
260	97.3	72	58.6	48.0	Maintenance & Labor = $1.84M/yr Fuel Costs = ($5.26 \times 10^6$ MBtu/yr) x fuel price ($/MBtu)
500	187.1	108.0	86.0	63.4	Maintenance & Labor = $2.46M/yr Fuel Cost = (9.84x106 MBtu/yr) x fuel price ($/MBtu)

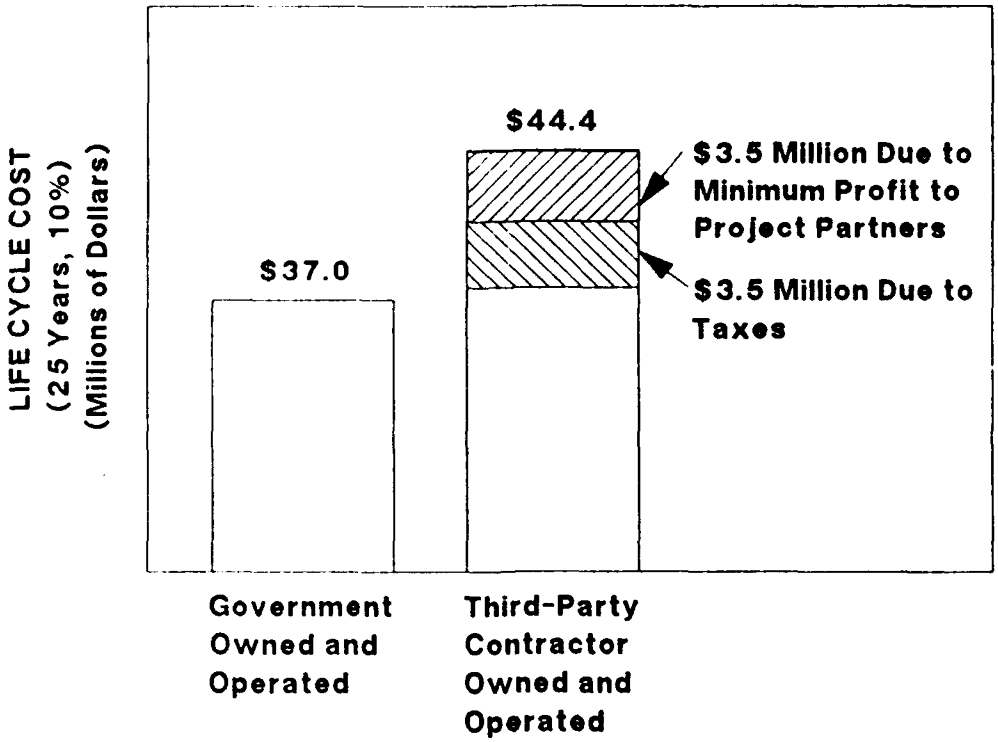

Figure 5. Comparison of life-cycle costs for heat supply with steam boilers (260 MBtu/hr maximum capacity).

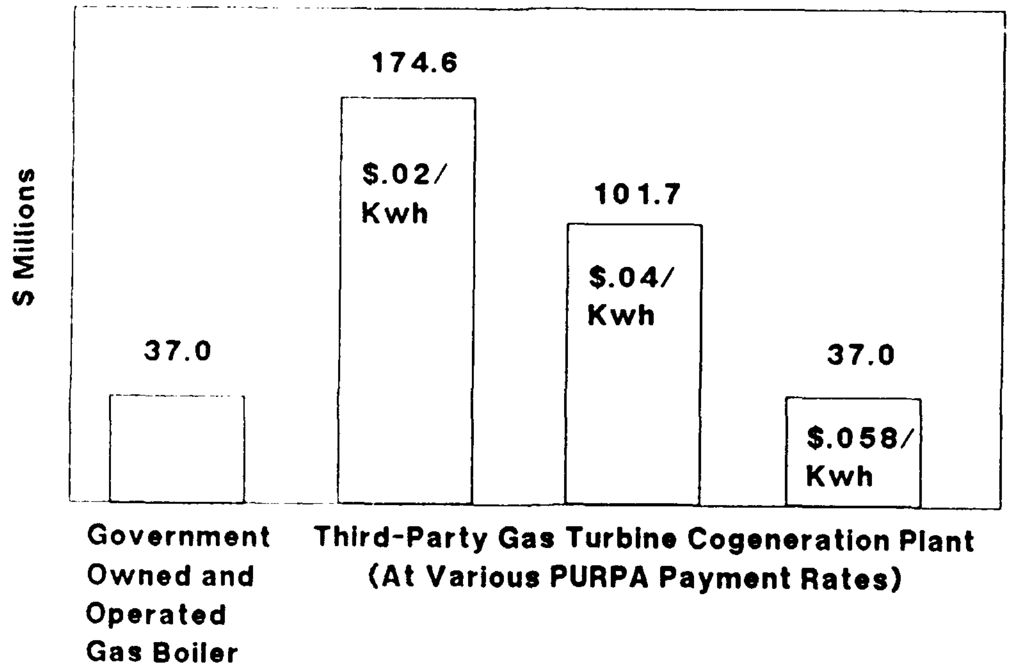

Figure 6. Life-cycle costs of Government and third-party heat supply gas boiler vs. gas turbine cogeneration.

charges for backup access to the local utility--essential to military missions unless other Government-owned backup generators with adequate capacity exist. Standby charges usually are calculated at a fixed rate per kilowatt of potentially required capacity per month. They are determined by a retrospective measurement of maximum demand during some prior period which varies by utility--referred to as the "demand ratchet."

For cogenerators, standby charges must be reasonable and nondiscriminatory under PURPA, Section 210. In fact, standby charges are in a state of revision, litigation, and change throughout the country. In most cases today, they range from $3 to $6/kW-month but vary widely; for this analysis, a standby rate of $4/kW-month was assumed and the peak electrical requirement of 35 MW was used to calculate the standby charge. Standby charges are an incremental cost and the value of electricity displaced is a savings to the Government.

As shown in Figure 7, life-cycle costs of thermal energy, assuming an average rate per kilowatt hour of utility electricity saved of 5¢ for industrial customers, are higher than for a gas boiler but lower than for a third-party cogenerator selling thermal energy and replacing utility electricity at the same rate (again due to incurrence of taxes and return on investment by the third party). USACERL's estimation showed that the value per kilowatt hour of electricity displaced by Government cogeneration would have to be at least 5.8¢/kWh to allow thermal life-cycle costs equivalent to a gas boiler--$37 million.

Case 6: Life-Cycle Cost of Third-Party Cogeneration--
Electricity Sold to Installation and Local Utility

In this case, elements of cases 4 and 5 above were combined--all electricity needed by the base (average generation of 20 MW) is sold by the third-party cogenerator at an average cost of 5¢ with standby charges as in Case 4. Remaining electrical capacity is sold to local utility under PURPA. For the third party to achieve life-cycle costs of thermal energy equal to a gas boiler (260 MBtu/hr and 37 percent average utilization), it must receive a PURPA payment of at least 6.8¢ (Figure 8). Thus, in this case, the average value of cogenerated electricity is slightly higher than if, as in Case 3 above, all were sold to the local utility at 6¢. This condition is due primarily to the incurrence of standby charges.

These results reflect general assumptions about many factors that will vary greatly by project:

1. Average industrial (or if applicable, wholesale) electrical rates for which the demand charge/per kilowatt component may vary.

2. Standby charges and how they are calculated.

3. Installation electrical consumption patterns relative to thermal energy (the more electricity consumed the lower the threshold rate to make the thermal life-cycle costs lower) and average thermal capacity utilization.

4. Any special incentives a local utility might offer for peak period generation either as part of a PURPA contract or from standby capacity.

Target Regions for Third-Party Heat Supply

Findings from the modeling study were analyzed to determine which geographic regions, if any, could expect to benefit economically from third-party heat suppliers. The McGraw-Hill Avoided-Cost Quarterly (last quarter of 1986) indicates that few utilities in the nation have listed avoided cost (PURPA) rates for

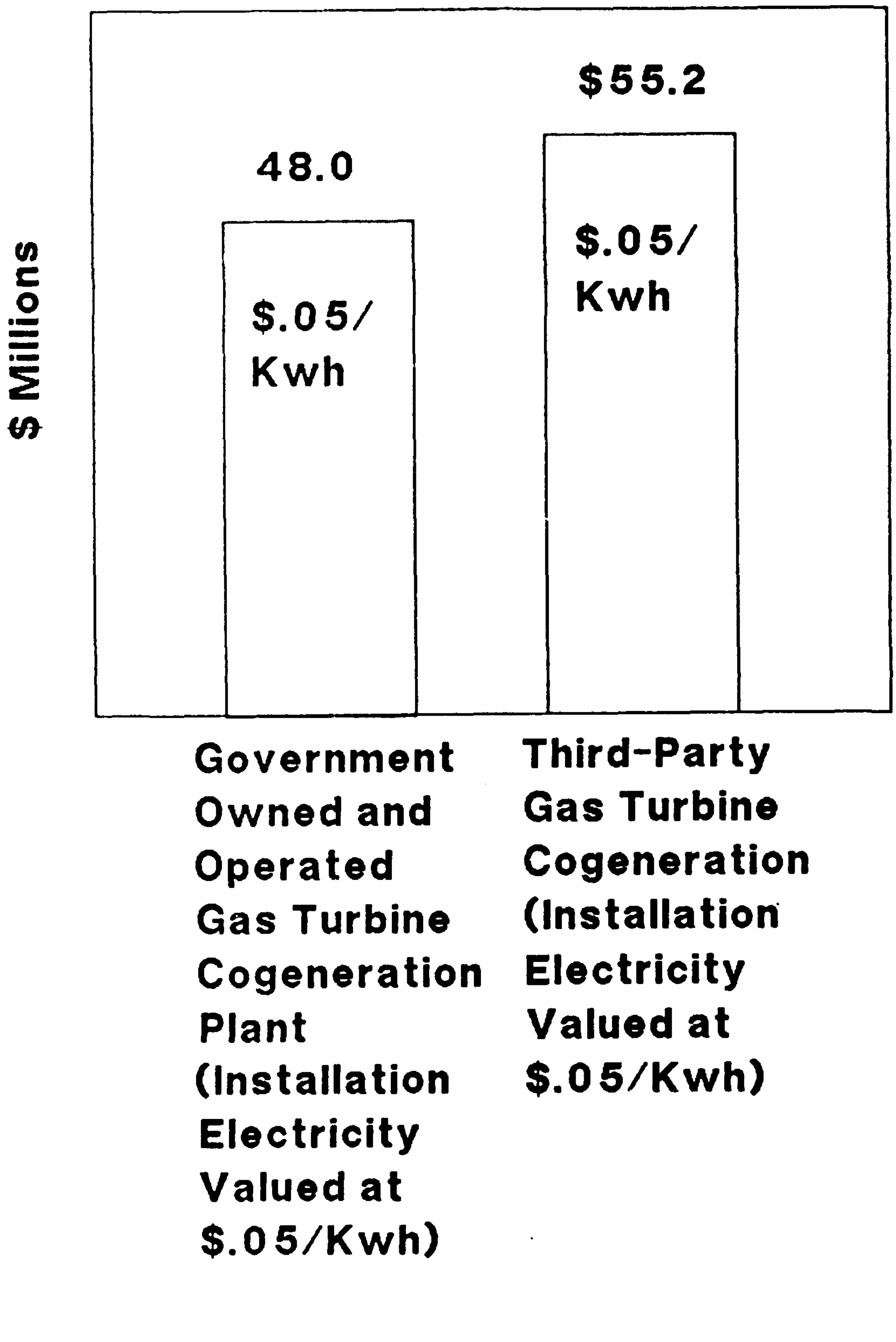

Figure 7. Life-cycle costs of Government and third-party heat supply; both with gas turbine cogeneration.

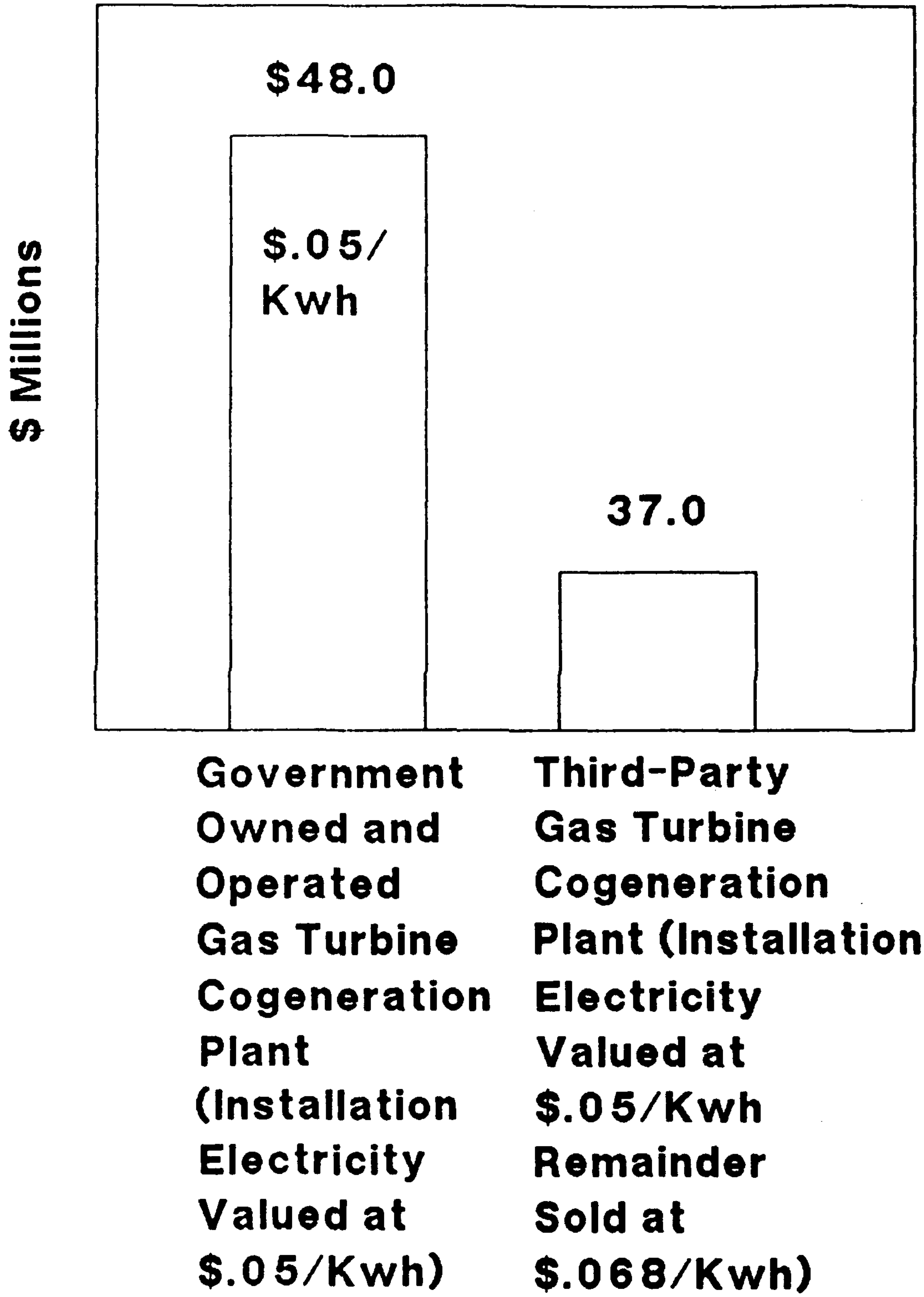

Figure 8. Life-cycle costs of Government and third-party heat supply using gas turbine congeneration, with third-party selling excess.

payment to third parties near the 6¢/kWh rate, and most are much lower. In fact, in most cases, the avoided cost payment would barely cover the variable costs of fuel per kilowatt hour which were estimated at 2.5¢ to 3¢ (coal-gas). This is not necessarily an indication of where third-party projects would work since PURPA payments for all projects over 500 KW are negotiated. A better indicator of where high PURPA payments might be available is in areas of rapid economic growth, which may lead to shortages of electrical generating capacity. In this case, high rates would likely reflect the relative value of incremental capacity. New England, and especially Massachusetts, are regarded as areas placing a high value on new capacity at this time sufficient to meet the 6¢/kWh target.

Assuming a preference against Government-owned and -operated cogeneration continues, development of third-party heat supply will need to be very selective. Were the Government to sell electricity from its own facility to the local utility in areas with 6¢/kWh or higher PURPA payments, it would likely always be the lower cost source of thermal energy on a life-cycle cost basis.

Therefore, it is concluded that third party-heat supply economics are unfavorable in most of the United States when compared with the life-cycle costs of Government-owned boilers except where a local utility favors small power supply because it needs additional capacity. This need for capacity now is very strong in New England and the Middle Atlantic States, making them prime areas for third-party project development.

5 CONCLUSIONS AND RECOMMENDATIONS

Conclusions

This study has analyzed the economics of using third-party contractors to supply central heat to Army installations as an alternative to Government-owned and -operated plants. The current third-party contract structure was evaluated and areas for improvement were identified. A financial modeling study was also performed using six hypothetical cases. Based on the findings of this investigation:

1. Gas-fired boilers for steam-only plants and gas turbines for cogeneration will likely be the lowest cost choice for thermal energy supply, other factors being equal, for all but the largest boilers (400 to 500 MBtu/hr maximum rated capacity); compared with these larger boilers, coal plants are less costly per unit of capacity.

2. Price and supply uncertainties in the past have been greater for gas than for coal and, thus, greater attention to supply security, backup fuels, and cost escalation indices would be needed than when coal is used as the fuel.

3. Thermal energy supplied by a third party from a gas-fired boiler rated at 260 MBtu/hr maximum capacity and 37 percent average usage is estimated to cost 20 percent more than that from a Government-owned and -operated gas boiler. Half of this extra cost is due to the taxes a third party must pay on profits from the project and half due to the minimum return (15 percent, inflation-adjusted) that the third-party contractor must earn on capital invested by partners in the project.

4. To reduce this life-cycle cost of thermal energy to a level at least equivalent to Government ownership, a third-party contractor must have profitable incremental revenues from cogenerated electricity that allow him to reduce charges to the Government for thermal energy--a rate of at least 5.8¢/kWh.

5. Based on this analysis, the minimum conditions for an economically feasible third-party project meeting the maximum thermal requirement of 260 MBtu/hr capacity at 37 percent average usage are:

- Gas turbine cogeneration plant;
- Location in areas such as the Middle Atlantic States (East Coast, Virginia, and North Carolina) and New England (New York, Connecticut, Vermont, New Hampshire, Massachussetts, Maine, and Rhode Island) where local utilities would likely be willing to pay a third party rates of 6¢/kWh or more, or;
- Military installations where the current average electrical rate is no less than 6¢/kWh to allow third-party cogeneration entirely for installation use--the minimum rate would be 5.8¢ if Government-owned cogeneration is possible.

Table 6 lists the most significant factors found to affect the life-cycle cost of thermal energy from a third-party supplier compared with a Government-owned plant. Table 7 summarizes third-party heat supply issues and the findings of this study. Based on these findings, a checklist was developed to help the Army determine optimal conditions for soliciting a third-party contract. By knowing before bid solicitation that a third-party contract will be economically feasible and by prequalifying bidders, the Government should be able to receive better bid response because the contractors' risk will be lowered. The checklist appears in Appendix G.

Table 6

Life-Cycle Costs ($M) to the Government of Alternative Thermal Energy Supply Choices

	Government Ownership and Operation	Third Party Ownership and Operation
Steam Only Plant	$37	$44
Cogeneration (steam and electricity) All electricity sold to installation (electricity valued at $0.5/Kwh)	$48	$55
Cogeneration (steam and electricity) with sale of all electricity to local utility ($.058/Kwh PURPA Payment)	Not Applicable	$37
Cogeneration with sale of electricity to both installation $.05/Kwh and local utility ($.068/Kwh)	Not Applicable	$37

Recommendations

1. To target potential third-party or Army-operated cogeneration projects, the Army should survey energy consumption at all installations to identify those with minimum steam or high-temperature hot water requirements of 20 to 25 MBtu/hr or greater which are supplied from central heating plants by boiler(s) likely to need replacement in the future.

2. Potential sites meeting the above criteria should be screened to exclude those in areas with low PURPA payments (below 6¢/kWh) or with low present electrical rates (below 6¢ to 7¢/kWh).

3. The remaining candidate sites should be evaluated, using the checklist in Appendix G, for economic feasibility of third-party contracting.

4. For those sites considered suitable, solicit qualified bidders using the checklist and existing contract requirements--modified where appropriate to include changes from the checklist.

Table 7

Summary of Third-Party Heat Supply Issues

Issues	Primary Impacts of Third-Party Life Cycle Costs and Risks Relative to Government Ownership and Operations	Findings
Technology	Operating and capital costs of steam boiler and cogeneration technology vary widely by scale and coal versus gas fuel	Low capital cost of gas-fired boilers and gas turbine for cogeneration make them low cost choice for both govt.and third-party for maximum thermal requirements up to 300-500 million Btu/hr at 37 percent capacity factor (average to maximum Btu's/hr
Fuel Choice	Minimal since both government and third party can choose most economical fuel	Fuel choice a function of optimal technology for the scale of heat requirements does not affect relative costs of Government and third-party ownership since each can choose most economical fuel
Financing Structure	Increased debt lowers average cost capital and reduces taxes for third-party projects	Dept financing alone cannot make third-party project less costly than similar Government and owned facility since third-party must still earn a profit on capital making the life cycle costs of third-party oilers (steam only) 20 percent more than Government ownership operate
Tax Law Reform	Reduces tax deductions associated with investment and lowers tax rate for projects of third-party contractors	Increases third-party life-cycle costs other things being equal by 30-40 percent (ADL Estimate)
PURPA (1978) Avoided Cost	Can lower third-party's thermal energy charges when payments exceed incremental cost of generation: region specific variable	Curremt rate too low in most areas in the U.S. to cover incremental costs of generation and reduce thermal costs (should be at least 6¢/Kwh; New England and the Middle Atlantic States are exceptions and are attractive areas for potential projects
Cost of Government-owned	Combined use of steam and electricity and avoidance of taxes and profit lower costs	Government-owned and operated cogeneration plants supply installation thermal and electric requirements at lower total life cycle costs (thermal and electric energy) than third party contracts

METRIC CONVERSION CHART

1 Btu	=	1.055 kJ
1 lb/hr	=	1.26×10^{-4} kg/sec
1 kWh	=	3.6 MJ
1 psig	=	6.895 kPa
1 in.	=	2.54 cm
°F	=	(°C x 1.8) + 32

REFERENCES

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18 CFR, *Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policy Act of 1978 With Regard to Small Power Production and Generation*, Subpart B, "Qualifying Cogeneration and Small Power Production Facilities" (1 April 1987).

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APPENDIX A: Government Gas-Fired Boiler Economics

C.E.R.L FINANCIAL MODEL
CASE I-GOVERNMENT OWNED-THERMAL ONLY-STAND ALONE GAS BOILER
RUN DATE: 6/15/88

ASSUMPTIONS: (all dollars in constant 1983 $ millions)	base year	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
BASE YEAR		1988									
FIRST YEAR OF PLANT OPERATION		1990									
Maximum Project Size (MMBtu/Hr.)	260.0										
BASIS (1988$ millions)		11.5									
POWER GENERATION DATA											
- Average Steam demand (MMBTU/Hr)	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
- Electricity demand (mw-avg)	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
- Electricity demand (mw) - max	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
- Loading											
- planned outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
- forced outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
- dispatch reserve		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
- Availability		95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
- Annual operating hours		8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
- summer hours		2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
- other hours		5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
- peak hours		2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
- off-peak hours		5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
- Btu output required (million Btu/hr)	97.3										
- Energy input - GAS (%)		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
- Energy input - GAS (million Btu/yr.)		964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0
UNIT FUEL COSTS (Gas)											
- Cost (base year $/mmbtu)	3.00										
- Price escalation rate (real)		.72%	.72%	.72%	.72%	.00%	.00%	.00%	.00%	.00%	.00%
- Price forecast ($/mmbtu)		3.02	3.04	3.07	3.09	3.09	3.09	3.09	3.09	3.09	3.09
OPERATING AND MAINTENANCE EXPENSES											
- Fixed cost ($ millions) ADL est.	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
- O & M escalation rate (real)	.00%		-.10%	-.80%	-.20%	.10%	.40%	.60%	.60%	.40%	.40%
INSURANCE (self insured)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
LIFE CYCLE COST											
DISCOUNT RATE (zero inflation)											
	10.00%										
PRO FORMA COST STATEMENT ($ millions)		1990	1991	1992	1993	1994	1995	1996	1997	1998	1999

	A	B	C	D	E	F	G	H	I	J	K	L	M
66	OPERATING EXPENSES												
68	Fuel												
69	- GAS			2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
70				.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
71	Total Fuel			2.9	2.9	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
73	Operations and Maintenance			.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
75	Insurance			.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
76				------	------	------	------	------	------	------	------	------	------
77	Total Operating Expenses			3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.8
78				======	======	======	======	======	======	======	======	======	======
82	CASH FLOW CALCULATIONS			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
85	TOTAL OPERATING EXPENSES			3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.8
87	CAPITAL INVESTMENT	5.8	5.8										
88		------	------	------	------	------	------	------	------	------	------	------	------
89	CASH FLOW	-5.8	-5.8	-3.7	-3.7	-3.7	-3.7	-3.7	-3.7	-3.7	-3.7	-3.8	-3.8
90		======	======	======	======	======	======	======	======	======	======	======	======
93	LIFE CYCLE COSTS			-37.4									

Row	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
7	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20	year 21	year 22	year 23	year 24	year 25
8	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
18	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
19	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
20	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
22	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
23	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
24	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
25	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
26	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
27	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
28	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
29	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
30	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
35	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
37	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0
42	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
43	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09	3.09
48	.5	.6	.6	.6	.6	.6	.6	.6	.6	.6	.6	.6	.6	.6	.6
50	.40%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%
53	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
62	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014

N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
.5	.6	.6	.6	.6	.6	.6	.6	.6	.6	.6	.6	.6	.6	.6
.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
======	======	======	======	======	======	======	======	======	======	======	======	======	======	======
2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8
======	======	======	======	======	======	======	======	======	======	======	======	======	======	======

C.E.R.L
CASE II-Thermal Only-Third Party GAS
RUN DATE: 6/15/88

ASSUMPTIONS:	base year	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
					% Debt	80.0%					
OPERATING TERM		23			% Equity	20.0%					
					Interest Rate						
BASE YEAR		1988			On Debt	11.0%					
FIRST YEAR OF PLANT OPERATION		1990									
- MAXIMUM THERMAL DEMAND-MMBtu/hr	260.0										
BASIS (1988$ millions)		11.5									
END-OF-LIFE SALVAGE VALUE (20% OF ORIGINAL COST)		.0									
DEPRECIATION RATES-1986 TAX LAW		5.00%	10.00%	9.00%	8.00%	7.00%	7.00%	6.00%	6.00%	6.00%	6.00%
POWER GENERATION DATA											
- Average Steam demand (MMBTU/Hr)	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
- Electricity demand (mw)	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
- Electricity demand (mw) - avg	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
- Loading											
- planned outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
- forced outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
- dispatch reserve		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
- Load factor		95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
- Annual operating hours		8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
- summer hours		2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
- other hours		5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
- peak hours		2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
- off-peak hours		5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
- Boiler efficiency - GAS		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
- Energy input - GAS (%)		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
- Energy input - GAS (million Btu/yr.)		964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0
		.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
FUEL DATA											
- Fuel Cost - Input											
- GAS cost ($/million Btu)		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
- Escalator		.7%	.7%	.7%	.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
- Average fuel cost ($/million Btu)		3.02	3.04	3.07	3.09	3.17	3.26	3.35	3.45	3.54	3.64
- Fuel Cost - Output											
- GAS cost ($/million Btu)		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
		.7%	.7%	.7%	.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
- Average fuel cost ($/million Btu)		3.02	3.04	3.07	3.09	3.17	3.26	3.35	3.45	3.54	3.64
VALUE OF STEAM CONSUMED											
- Value to (base year $/MMBTU)	3.900										
- Value to Others (base year $/MMBTU)	3.900										
- Steam value escalation rate (real)			-.1%	-.8%	-.2%	.1%	.4%	.6%	.6%	.4%	.4%
- Value forecast ($/MMBTU)		3.900	3.896	3.865	3.857	3.861	3.877	3.900	3.923	3.939	3.955

A	B	C	D	E	F	G	H	I	J	K	L	M
VALUE OF ELECTRICITY CONSUMED												
· Elect. value (base year cents/kwh)		.000										
· Electricity escalation rate (real)		.000		.000	.000	.000	.000	.000	.000	.000	.000	.000
· Elect. value forecast (cents/kwh)			.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
OPERATING AND MAINTENANCE EXPENSES												
· Fixed cost ($ millions) ADL est.		.500	.500	.500	.496	.495	.495	.497	.500	.503	.505	.507
· O & M escalation rate (real)		.00%		-.10%	-.80%	-.20%	.10%	.40%	.60%	.60%	.40%	.40%
INSURANCE			2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
INTEREST PAYMENT SCHEDULE			11.00%	10.30%	9.60%	8.80%	.08	6.90%	5.80%	4.50%	3.20%	1.70%
PRINCIPAL REPAYMENT SCHEDULE			6.00%	6.70%	7.40%	8.20%	9.10%	10.10%	11.20%	12.50%	13.80%	15.30%
DISCOUNT RATES (zero inflation)		15.00%										
FEDERAL/STATE TAX RATE			37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%
INVESTMENT TAX CREDIT			.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
ENERGY TAX CREDIT			.00%									
PRO FORMA INCOME STATEMENT ($ millions)			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
REVENUES												
Value of steam consumed-capacity charge			3.2	3.2	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2
Value of steam-fuel charge			2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.8	2.9	3.0
Value of electricity consumed			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Electricity sales			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Revenues			5.6	5.6	5.6	5.6	5.7	5.8	5.9	6.0	6.1	6.2
TOTAL VALUE OF STEAM REVENUES			5.6	5.6	5.6	5.6	5.7	5.8	5.9	6.0	6.1	6.2
PRESENT VALUE OF STEAM REVENUES			53.8									
OPERATING EXPENSES												
Total Fuel Cost			2.9	2.9	3.0	3.0	3.1	3.1	3.2	3.3	3.4	3.5
Operations and Maintenance			.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
Property Taxes and Insurance			.1	.2	.2	.2	.2	.2	.2	.2	.2	.2
Total Operating Expenses			3.5	3.7	3.7	3.7	3.8	3.9	4.0	4.1	4.2	4.2
OPERATING CASH MARGIN			2.1	2.0	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
INTEREST EXPENSE			1.0	.9	.9	.8	.7	.6	.5	.4	.3	.2

	A	B	C	D	E	F	G	H	I	J	K	L	M
131	DEPRECIATION			.6	1.2	1.0	.9	.8	.8	.7	.7	.7	.7
134	TAXABLE INCOME			.5	-.1	.0	.2	.4	.5	.7	.8	.9	1.1
137	INCOME TAXES			.2	.0	.0	.1	.1	.2	.2	.3	.3	.4
138	TAX CREDITS			.0									
140	AFTER TAX INCOME			.3	-.1	.0	.1	.2	.3	.4	.5	.6	.7
145	CASH FLOW CALCULATIONS			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
148	AFTER TAX INCOME			.3	-.1	.0	.1	.2	.3	.4	.5	.6	.7
150	DEPRECIATION			.6	1.2	1.0	.9	.8	.8	.7	.7	.7	.7
152	INVESTMENT & PRINCIPAL PMT	1.2	1.2	.6	.6	.7	.8	.8	.9	1.0	1.2	1.3	1.4
154	WORKING CAPITAL			.7	.0	.0	.0	.0	.0	.0	.0	.0	.0
156	CASH FLOW	-1.2	-1.2	-.3	.4	.4	.3	.2	.2	.1	.1	.0	.0
160	PRESENT VALUE AT 0%			.0									
162	IRR			15.1%									
164	Annual Capacity and Fuel Charges			5.6	5.6	5.6	5.6	5.7	5.8	5.9	6.0	6.1	6.2
165	LIFE CYCLE COST TO GOVERNMENT			44.4									

	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
7	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20	year 21	year 22	year 23	year 24	year 25
8	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
20	6.00%	6.00%	6.00%	6.00%	6.00%										
24	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
25	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
26	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
28	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
29	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
30	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
31	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
32	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
33	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
34	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
35	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
36	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
37	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
38	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
43	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
44	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
45	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0	964000.0
46	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
51	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
52	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
53	3.75	3.85	3.96	4.07	4.18	4.30	4.42	4.54	4.67	4.80	4.94	5.08	5.22	5.36	5.51
55	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
56	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
57	3.75	3.85	3.96	4.07	4.18	4.30	4.42	4.54	4.67	4.80	4.94	5.08	5.22	5.36	5.51
63	.4%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%
64	3.970	3.982	3.994	4.006	4.018	4.030	4.042	4.055	4.067	4.079	4.091	4.103	4.116	4.128	4.140

	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
71	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
72	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
77	.509	.511	.512	.514	.515	.517	.518	.520	.521	.523	.525	.526	.528	.529	.531
79	.40%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%
82	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
92	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%
93	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
98	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
104	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.4
105	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.5
106	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
108	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
109	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
110	6.2	6.3	6.4	6.5	6.6	6.7	6.9	7.0	7.1	7.2	7.3	7.4	7.6	7.7	7.8
112	6.2	6.3	6.4	6.5	6.6	6.7	6.9	7.0	7.1	7.2	7.3	7.4	7.6	7.7	7.8
118	3.6	3.7	3.8	3.9	4.0	4.1	4.3	4.4	4.5	4.6	4.8	4.9	5.0	5.2	5.3
120	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
122	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
123	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
124	4.3	4.5	4.6	4.7	4.8	4.9	5.0	5.1	5.3	5.4	5.5	5.6	5.8	5.9	6.1
127	1.9	1.9	1.9	1.9	1.9	1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.7
129	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0

	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
131	.7	.7	.7	.7	.7	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
134	1.2	1.2	1.2	1.2	1.2	1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.7
137	.4	.4	.4	.4	.4	.7	.6	.6	.6	.6	.6	.6	.6	.6	.6
140	.8	.8	.8	.8	.8	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.1
145	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
148	.8	.8	.8	.8	.8	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.1
150	.7	.7	.7	.7	.7	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
152	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
154	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
156	1.5	1.5	1.5	1.4	1.4	1.2	1.2	1.2	1.2	1.2	1.2	1.1	1.1	1.1	1.1
164	6.2	6.3	6.4	6.5	6.6	6.7	6.9	7.0	7.1	7.2	7.3	7.4	7.6	7.7	7.8

APPENDIX C: Third-Party Gas Turbine Cogeneration Economics (PURPA)

C.E.R.L
CASE IIIc-Cogeneration-GAS TURBINE-$0.058/KWHR
RUN DATE: 6/15/88

A	C	D	E	F	G	H	I	J	K	L	M
ASSUMPTIONS:	base year	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
					% Debt	80.0%					
OPERATING TERM (years)		23			% Equity	20.0%					
					Interest Rate						
BASE YEAR		1988			On Debt	11.0%					
FIRST YEAR OF PLANT OPERATION		1990									
- MAXIMUM THERMAL DEMAND-MMBtu/hr	260.0										
BASIS (1988$ millions)		48.0									
END-OF-LIFE SALVAGE VALUE (20% OF ORIGINAL COST)		9.6									
DEPRECIATION RATES-1986 TAX LAW		5.00%	10.00%	9.00%	8.00%	7.00%	7.00%	6.00%	6.00%	6.00%	6.00%
POWER GENERATION DATA											
- Average steam demand (MMBTU/Hr)	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
- Electricity consumed (mw)	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
- Electricity demand (mw) - avg	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6
- Loading											
- planned outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
- forced outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
- dispatch reserve		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
- Load factor		95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
- Annual operating hours		8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
- summer hours		2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
- other hours		5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
- peak hours		2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
- off-peak hours		5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
- Boiler output required (million Btu/yr.)		6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0
- Energy input - GAS (%)		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
- Energy input - GAS (million Btu/yr.)		6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0
		.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
FUEL DATA											
- Fuel Cost - Input											
- GAS cost ($/million Btu)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
- Escalator		.7%	.7%	.7%	.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
- Average fuel cost ($/million Btu)		3.02	3.04	3.07	3.09	3.17	3.26	3.35	3.45	3.54	3.64
- Fuel Cost - Output											
- GAS cost ($/million Btu)	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
		.7%	.7%	.7%	.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
- Average fuel cost ($/million Btu)		3.02	3.04	3.07	3.09	3.17	3.26	3.35	3.45	3.54	3.64
VALUE OF STEAM CONSUMED											
- Value to (base year $/MMBTU)	2.725										
- Value to Others (base year $/MMBTU)	2.725										
- Steam value escalation rate (real)			-.1%	-.8%	-.2%	.1%	.4%	.6%	.6%	.4%	.4%
- Value forecast ($/MMBTU)		2.725	2.722	2.700	2.695	2.698	2.709	2.725	2.741	2.752	2.763

Row	A	B	C	D	E	F	G	H	I	J	K	L	M
68	VALUE OF ELECTRICITY CONSUMED												
70	· Elect. value (base year cents/kwh)		5.825										
71	· Electricity escalation rate (real)		.000		.000	.000	.000	.000	.000	.000	.000	.000	.000
72	· Elect. value forecast (cents/kwh)			5.825	5.825	5.825	5.825	5.825	5.825	5.825	5.825	5.825	5.825
76	OPERATING AND MAINTENANCE EXPENSES												
77	· Fixed cost ($ millions) ADL est.		1.840	1.840	1.838	1.823	1.820	1.822	1.829	1.840	1.851	1.858	1.866
79	· O & M escalation rate (real)		.00%	.00%	-.10%	-.80%	-.20%	.10%	.40%	.60%	.60%	.40%	.40%
82	INSURANCE			2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
84	INTEREST PAYMENT SCHEDULE			11.00%	10.30%	9.60%	8.80%	.08	6.90%	5.80%	4.50%	3.20%	1.70%
85	PRINCIPAL REPAYMENT SCHEDULE			6.00%	6.70%	7.40%	8.20%	9.10%	10.10%	11.20%	12.50%	13.80%	15.30%
87	DISCOUNT RATES (zero inflation)												
88			15.00%										
92	FEDERAL/STATE TAX RATE			37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%
93	INVESTMENT TAX CREDIT			.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
94	ENERGY TAX CREDIT			.00%									
98	PRO FORMA INCOME STATEMENT ($ millions)			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
102	REVENUES												
104	Value of steam consumed-capacity charge			2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
105	Value of steam-fuel charge			2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.8	2.9	3.0
106	Value of electricity consumed			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
108	Electricity sales			28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4
110	Total Revenues			33.1	33.1	33.1	33.1	33.2	33.2	33.3	33.4	33.5	33.6
112	TOTAL VALUE OF STEAM REVENUES			4.7	4.7	4.7	4.7	4.8	4.8	4.9	5.0	5.1	5.2
113	PRESENT VALUE OF STEAM REVENUES			45.2									
115	OPERATING EXPENSES												
118	Total Fuel Cost			19.8	20.0	20.1	20.3	20.8	21.4	22.0	22.6	23.3	23.9
120	Operations and Maintenance			1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9
122	Property Taxes and Insurance			.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
124	Total Operating Expenses			22.1	22.8	22.9	23.0	23.6	24.2	24.8	25.4	26.1	26.7
127	OPERATING CASH MARGIN			10.9	10.3	10.2	10.1	9.6	9.0	8.5	8.0	7.4	6.9
129	INTEREST EXPENSE			4.2	4.0	3.7	3.4	3.0	2.6	2.2	1.7	1.2	.7

Row	A	B	C	D	E	F	G	H	I	J	K	L	M
131	DEPRECIATION			2.4	4.8	4.3	3.8	3.4	3.4	2.9	2.9	2.9	2.9
134	TAXABLE INCOME			4.3	1.6	2.2	2.8	3.2	3.0	3.4	3.4	3.3	3.3
137	INCOME TAXES			1.6	.5	.8	1.0	1.1	1.1	1.2	1.2	1.2	1.2
138	TAX CREDITS			.0									
140	AFTER TAX INCOME			2.7	1.0	1.4	1.8	2.1	2.0	2.2	2.2	2.2	2.2
145	CASH FLOW CALCULATIONS			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
148	AFTER TAX INCOME			2.7	1.0	1.4	1.8	2.1	2.0	2.2	2.2	2.2	2.2
150	DEPRECIATION			2.4	4.8	4.3	3.8	3.4	3.4	2.9	2.9	2.9	2.9
152	INVESTMENT & PRINCIPAL PMT	4.8	4.8	2.3	2.6	2.8	3.1	3.5	3.9	4.3	4.8	5.3	5.9
154	WORKING CAPITAL			4.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
156	CASH FLOW	-4.8	-4.8	-1.2	3.2	2.9	2.5	1.9	1.4	.8	.3	-.3	-.8
160	PRESENT VALUE AT 15%			.1									
162	IRR			15.2%									
164	Annual Capacity and Fuel Charges			4.7	4.7	4.7	4.7	4.8	4.8	4.9	5.0	5.1	5.2
165	LIFE CYCLE COST TO GOVERNMENT			37.4									

Row	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
7	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20	year 21	year 22	year 23	year 24	year 25
8	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
20	6.00%	6.00%	6.00%	6.00%	6.00%										
24	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
25	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
26	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6
28	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
29	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
30	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
31	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
32	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
33	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
34	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
35	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
36	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
42	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0
43	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
44	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
45	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0
46	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
51	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
52	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
53	3.75	3.85	3.96	4.07	4.18	4.30	4.42	4.54	4.67	4.80	4.94	5.08	5.22	5.36	5.51
55	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
56	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
57	3.75	3.85	3.96	4.07	4.18	4.30	4.42	4.54	4.67	4.80	4.94	5.08	5.22	5.36	5.51
63	.4%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%
64	2.774	2.783	2.791	2.799	2.808	2.816	2.825	2.833	2.841	2.850	2.859	2.867	2.876	2.884	2.893

Row	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
71	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
72	5.825	5.825	5.825	5.825	5.825	5.825	5.825	5.825	5.825	5.825	5.825	5.825	5.825	5.825	5.825
77	1.873	1.879	1.884	1.890	1.896	1.901	1.907	1.913	1.919	1.924	1.930	1.936	1.942	1.948	1.953
79	.40%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%
82	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
92	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%
93	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
98	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
104	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
105	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.5
106	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
108	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4	28.4
110	33.7	33.8	33.9	34.0	34.1	34.2	34.3	34.4	34.5	34.6	34.7	34.8	35.0	35.1	35.2
112	5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.0	6.1	6.2	6.3	6.4	6.6	6.7	6.8
118	24.6	25.3	26.0	26.7	27.4	28.2	29.0	29.8	30.6	31.5	32.4	33.3	34.2	35.2	36.2
120	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.0
122	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
124	27.4	28.1	28.8	29.5	30.3	31.1	31.9	32.7	33.5	34.4	35.3	36.2	37.1	38.1	39.1
127	6.3	5.7	5.1	4.4	3.8	3.1	2.4	1.7	1.0	.2	-.6	-1.4	-2.2	-3.0	-3.9
129	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0

	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
131	2.9	2.9	2.9	2.9	2.9	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
133	3.4	2.8	2.2	1.5	.9	3.1	2.4	1.7	1.0	.2	-.6	-1.4	-2.2	-3.0	-3.9
136	1.2	1.0	.8	.5	.3	1.1	.8	.6	.3	.1	-.2	-.5	-.8	-1.1	-1.4
139	2.2	1.8	1.4	1.0	.6	2.0	1.6	1.1	.6	.1	-.4	-.9	-1.4	-1.9	-2.5
140	======	======	======	======	======	======	======	======	======	======	======	======	======	======	======
142	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
144	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
145	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
147	2.2	1.8	1.4	1.0	.6	2.0	1.6	1.1	.6	.1	-.4	-.9	-1.4	-1.9	-2.5
149	2.9	2.9	2.9	2.9	2.9	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
151	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
153	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
154	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
155	5.1	4.7	4.3	3.9	3.4	2.0	1.5	1.1	.6	.1	-.4	-.9	-1.4	-2.0	-2.5
156	======	======	======	======	======	======	======	======	======	======	======	======	======	======	======
163	5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.0	6.1	6.2	6.3	6.4	6.6	6.7	6.8

A	B	C	D	E	F	G	H	I	J	K	L	M

C.E.R.L
CASE IV-DOD Owned-Cogeneration-GAS TURBINE-Electricity sales to base only
RUN DATE: 6/15/88

ASSUMPTIONS: (all dollars in millions)	base year	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
PROJECT TERM (years)		23									
BASE YEAR		1988									
FIRST YEAR OF PLANT OPERATION		1990									
- MAXIMUM THERMAL DEMAND-MMBtu/hr	260.0										
BASIS (1988$ millions)		25.8									
END-OF-LIFE SALVAGE VALUE (20% OF ORIGINAL COST)		5.2									
POWER GENERATION DATA											
- Steam demand (MMBTU/Hr)	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
- Electricity sales (mw) - avg	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6
- Loading											
- planned outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
- forced outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
- dispatch reserve		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
- Load factor		95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
- Annual operating hours		8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
- summer hours		2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
- other hours		5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
- peak hours		2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
- off-peak hours		5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
- Boiler efficiency - GAS											
- Energy Input - GAS (%)		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
- Energy Input - GAS (million Btu/yr)		2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0
		.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
FUEL DATA											
- Fuel Cost - Input											
- GAS cost ($/million Btu)		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
- Escalator		.7%	.7%	.7%	.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
- Average fuel cost ($/million Btu)		3.02	3.04	3.07	3.09	3.17	3.26	3.35	3.45	3.54	3.64
- Fuel Cost - Output											
- GAS cost ($/million Btu)		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
		.7%	.7%	.7%	.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
- Average fuel cost ($/million Btu)		3.02	3.04	3.07	3.09	3.17	3.26	3.35	3.45	3.54	3.64
VALUE OF STEAM CONSUMED											
- Value to (base year $/MMBTU)	N.A.										
- Value to Others (base year $/MMBTU)	N.A.										
- Steam value escalation rate (real)			-.1%	-.8%	-.2%	.1%	.4%	.6%	.6%	.4%	.4%
- Value forecast ($/MMBTU)		.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
- Others value forecast ($/MMBTU)		.000	.000	.000	.000	.000	.000	.000	.000	.000	.000

	A	B	C	D	E	F	G	H	I	J	K	L	M
66													
67													
68	VALUE OF ELECTRICITY CONSUMED												
69													
70	· Elect. value (base year cents/kwh)		5.000										
71	· Electricity escalation rate (real)		.000		.000	.000	.000	.000	.000	.000	.000	.000	.000
72	· Elect. value forecast (cents/kwh)			5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000
73													
74													
75													
76	OPERATING AND MAINTENANCE EXPENSES												
77	· Fixed cost ($ millions) ADL est.		1.000	1.000	.999	.991	.989	.990	.994	1.000	1.006	1.010	1.014
78	· Variable cost ($ millions/100% load)		.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
79	· O & M escalation rate (real)		.00%		-.10%	-.80%	-.20%	.10%	.40%	.60%	.60%	.40%	.40%
80													
81													
82	INSURANCE			2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
83													
84	INTEREST PAYMENT SCHEDULE												
85	PRINCIPAL REPAYMENT SCHEDULE												
86													
87	DISCOUNT RATES (zero inflation)												
88			.00%										
89													
90													
91													
92	FEDERAL/STATE TAX RATE			.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
93	INVESTMENT TAX CREDIT			.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
94	ENERGY TAX CREDIT			.00%									
95													
96													
97													
98	PRO FORMA INCOME STATEMENT ($ millions)			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
99													
100													
101													
102	COST REDUCTIONS												
103													
104	Value of steam consumed-capacity charge			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
105	Value of steam-fuel charge			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
106	Value of electricity consumed			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
107													
108	Value of Electricity Displaced			8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
109				------	------	------	------	------	------	------	------	------	------
110	Total Cost Reductions			8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
111													
112	TOTAL VALUE OF STEAM REVENUES			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
113	PRESENT VALUE OF STEAM (TEN PERCENT)			.0									
114													
115	OPERATING EXPENSES												
116													
117													
118	Total Fuel Cost			7.4	7.5	7.5	7.6	7.8	8.0	8.3	8.5	8.7	9.0
119	Standby charges ($4.00/kw/month,35,000kw required)			1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
120	Operations and Maintenance			1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
121													
122	Insurance			.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
123				------	------	------	------	------	------	------	------	------	------
124	Total Operating Expenses			10.6	10.7	10.7	10.8	11.0	11.2	11.4	11.7	11.9	12.2
125													
126													
127	OPERATING CASH MARGIN			-2.1	-2.1	-2.2	-2.2	-2.4	-2.7	-2.9	-3.1	-3.4	-3.6
128													
129	INTEREST EXPENSE			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
130													

	A	B	C	D	E	F	G	H	I	J	K	L	M
131	DEPRECIATION			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
132													
133													
134	TAXABLE INCOME			-2.1	-2.1	-2.2	-2.2	-2.4	-2.7	-2.9	-3.1	-3.4	-3.6
135													
136													
137	INCOME TAXES			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
138	TAX CREDITS			.0									
139													
140	AFTER TAX INCOME			-2.1	-2.1	-2.2	-2.2	-2.4	-2.7	-2.9	-3.1	-3.4	-3.6
141				======	======	======	======	======	======	======	======	======	======
142													
143	----------------------------												
144													
145	CASH FLOW CALCULATIONS			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
146	----------------------------												
147													
148	AFTER TAX INCOME			-2.1	-2.1	-2.2	-2.2	-2.4	-2.7	-2.9	-3.1	-3.4	-3.6
149													
150	DEPRECIATION			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
151													
152	INVESTMENT & PRINCIPAL PMT	12.9	12.9	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
153													
154	WORKING CAPITAL			1.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
155		------	------	------	------	------	------	------	------	------	------	------	------
156	CASH FLOW	-12.9	-12.9	-3.1	-2.1	-2.2	-2.2	-2.4	-2.7	-2.9	-3.1	-3.4	-3.6
157		======	======	======	======	======	======	======	======	======	======	======	======
158													
159													
160	PRESENT VALUE AT 15%			-126.6									
161													
162	IRR		N.A.										
163													
164	Annual Capacity and Fuel Charg	-12.9	-12.9	-3.1	-2.1	-2.2	-2.2	-2.4	-2.7	-2.9	-3.1	-3.4	-3.6
165	LIFE CYCLE COST TO GOVERNMENT			-47.9									

	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
7	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20	year 21	year 22	year 23	year 24	year 25
8	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
24	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
26	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6
28	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
29	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
30	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
31	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
32	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
33	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
34	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
35	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
36	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
43	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
44	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
45	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0
46	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
51	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
52	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
53	3.75	3.85	3.96	4.07	4.18	4.30	4.42	4.54	4.67	4.80	4.94	5.08	5.22	5.36	5.51
55	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
56	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
57	3.75	3.85	3.96	4.07	4.18	4.30	4.42	4.54	4.67	4.80	4.94	5.08	5.22	5.36	5.51
63	.4%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%
64	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
65	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000

Row	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
71	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
72	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000
77	1.018	1.021	1.024	1.027	1.030	1.033	1.037	1.040	1.043	1.046	1.049	1.052	1.055	1.058	1.062
78	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	000
79	.40%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	30%
82	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
92	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
93	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
98	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	0'.
104	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
105	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
106	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
108	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
110	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
112	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
118	9.2	9.5	9.7	10.0	10.3	10.6	10.9	11.2	11.5	11.8	12.1	12.5	12.8	13.2	13.6
119	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
120	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1
122	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
124	12.4	12.7	13.0	13.2	13.5	13.8	14.1	14.4	14.7	15.1	15.4	15.7	16.1	16.4	16.8
127	-3.9	-4.1	-4.4	-4.7	-5.0	-5.3	-5.6	-5.9	-6.2	-6.5	-6.8	-7.2	-7.5	-7.9	-8.3
129	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0

	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
131	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
134	-3.9	-4.1	-4.4	-4.7	-5.0	-5.3	-5.6	-5.9	-6.2	-6.5	-6.8	-7.2	-7.5	-7.9	-8.3
137	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
140	-3.9	-4.1	-4.4	-4.7	-5.0	-5.3	-5.6	-5.9	-6.2	-6.5	-6.8	-7.2	-7.5	-7.9	-8.3
141	======	======	======	======	======	======	======	======	======	======	======	======	======	======	======
145	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
148	-3.9	-4.1	-4.4	-4.7	-5.0	-5.3	-5.6	-5.9	-6.2	-6.5	-6.8	-7.2	-7.5	-7.9	-8.3
150	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
152	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
154	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
156	-3.9	-4.1	-4.4 -	-4.7	-5.0	-5.3	-5.6	-5.9	-6.2	-6.5	-6.8	-7.2	-7.5	-7.9	-8.3
157	======	======	======	======	======	======	======	======	======	======	======	======	======	======	======
164	-3.9	-4.1	-4.4	-4.7	-5.0	-5.3	-5.6	-5.9	-6.2	-6.5	-6.8	-7.2	-7.5	-7.9	-8.3

APPENDIX E: Third-Party Cogeneration-Electricity Sales To Base Only

| A || B || C || D || E || F || G || H || I || J || K || L || M |

C.E.R.L
CASE V-Cogeneration-Third Party GAS TURBINE-Electricity sales to base only
RUN DATE: 6/15/88

ASSUMPTIONS:	base year	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
					% Debt	80.0%					
OPERATING TERM (years)		23			% Equity	20.0%					
					Interest Rate On Debt	11.0%					
BASE YEAR		1988									
FIRST YEAR OF PLANT OPERATION		1990									
- MAXIMUM THERMAL DEMAND-MMBtu/hr	260.0										
BASIS (1988$ millions)		25.8									
END-OF-LIFE SALVAGE VALUE (20% OF ORIGINAL COST)		5.2									
DEPRECIATION RATES-1986 TAX LAW		5.00%	10.00%	9.00%	8.00%	7.00%	7.00%	6.00%	6.00%	6.00%	6.00%
POWER GENERATION DATA											
- Average Steam demand (MMBTU/Hr)	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
- Electricity consumed (mw)-avg	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6
- Loading											
- planned outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
- forced outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
- dispatch reserve		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
- Load factor		95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
- Annual operating hours		8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
- summer hours		2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
- other hours		5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
- peak hours		2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
- off-peak hours		5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
- Energy input - GAS (%)		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
- Energy input - GAS (million Btu/yr)		2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0
		.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
FUEL DATA											
- Fuel Cost - Input											
- GAS cost ($/million Btu)		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
- Escalator		.7%	.7%	.7%	.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
- Average fuel cost ($/million Btu)		3.02	3.04	3.07	3.09	3.17	3.26	3.35	3.45	3.54	3.64
- *Fuel Cost - Output*											
- GAS cost ($/million Btu)		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
		.7%	.7%	.7%	.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
- Average fuel cost ($/million Btu)		3.02	3.04	3.07	3.09	3.17	3.26	3.35	3.45	3.54	3.64
VALUE OF STEAM CONSUMED											
- Value to (base year $/MMBTU)	5.700										
- Value to Others (base year $/MMBTU)	5.700										
- Steam value escalation rate (real)			-.1%	-.8%	-.2%	.1%	.4%	.6%	.6%	.4%	.4%
- Value forecast ($/MMBTU)		5.700	5.694	5.649	5.637	5.643	5.666	5.700	5.734	5.757	5.780
- *Others value forecast ($/MMBTU)*		5.700	5.694	5.649	5.637	5.643	5.666	5.700	5.734	5.757	5.780

A	B	C	D	E	F	G	H	I	J	K	L	M
VALUE OF ELECTRICITY CONSUMED												
- Elect. value (base year cents/kwh)		5.000										
- Electricity escalation rate (real)		.000		.000	.000	.000	.000	.000	.000	.000	.000	.000
- Elect. value forecast (cents/kwh)			5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000
OPERATING AND MAINTENANCE EXPENSES												
- Fixed cost ($ millions) ADL est.		1.000	1.000	.999	.991	.989	.990	.994	1.000	1.006	1.010	1.014
- Variable cost ($ millions/100% load)		.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
- O & M escalation rate (real)		.00%		-.10%	-.80%	-.20%	.10%	.40%	.60%	.60%	.40%	.40%
INSURANCE			2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
INTEREST PAYMENT SCHEDULE			11.00%	10.30%	9.60%	8.80%	.08	6.90%	5.80%	4.50%	3.20%	1.70%
PRINCIPAL REPAYMENT SCHEDULE			6.00%	6.70%	7.40%	8.20%	9.10%	10.10%	11.20%	12.50%	13.80%	15.30%
DISCOUNT RATES (zero inflation)												
		15.00%										
FEDERAL/STATE TAX RATE			37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%
INVESTMENT TAX CREDIT			.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
ENERGY TAX CREDIT			.00%									
PRO FORMA INCOME STATEMENT ($ millions)			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
REVENUES												
Value of steam consumed-capacity charge			4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.7	4.7
Value of steam-fuel charge			2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.8	2.9	3.0
Value of electricity consumed			.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Electricity sales			8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Total Revenues			15.6	15.6	15.6	15.6	15.7	15.8	15.9	16.0	16.1	16.2
TOTAL VALUE OF STEAM REVENUES			7.1	7.1	7.1	7.1	7.1	7.2	7.3	7.4	7.5	7.6
PRESENT VALUE OF STEAM REVENUES			66.8									
OPERATING EXPENSES												
Total Fuel Cost			7.4	7.5	7.5	7.6	7.8	8.0	8.3	8.5	8.7	9.0
Standby charges ($4.00/kw/month,35,000kw required)			1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Operations and Maintenance			1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Property Taxes and Insurance			.3	.5	.5	.5	.5	.5	.5	.5	.5	.5
Total Operating Expenses			10.4	10.7	10.7	10.8	11.0	11.2	11.4	11.7	11.9	12.2
OPERATING CASH MARGIN			5.2	4.9	4.9	4.8	4.7	4.6	4.4	4.3	4.2	4.0
INTEREST EXPENSE			2.3	2.1	2.0	1.8	1.6	1.4	1.2	.9	.7	.4

A	B	C	D	E	F	G	H	I	J	K	L	M
DEPRECIATION			1.3	2.6	2.3	2.1	1.8	1.8	1.5	1.5	1.5	1.5
TAXABLE INCOME			1.7	.2	.6	1.0	1.3	1.3	1.7	1.8	1.9	2.1
INCOME TAXES			.6	.1	.2	.3	.4	.5	.6	.6	.7	.7
TAX CREDITS			.0									
AFTER TAX INCOME			1.1	.2	.4	.6	.8	.9	1.1	1.2	1.3	1.4
CASH FLOW CALCULATIONS			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
AFTER TAX INCOME			1.1	.2	.4	.6	.8	.9	1.1	1.2	1.3	1.4
DEPRECIATION			1.3	2.6	2.3	2.1	1.8	1.8	1.5	1.5	1.5	1.5
INVESTMENT & PRINCIPAL PMT	2.6	2.6	1.2	1.4	1.5	1.7	1.9	2.1	2.3	2.6	2.8	3.2
WORKING CAPITAL			1.9	.0	.0	.0	.0	.0	.0	.0	.0	.0
CASH FLOW	-2.6	-2.6	-.8	1.4	1.2	1.0	.7	.6	.3	.1	.0	-.3
PRESENT VALUE AT 15%			.1									
IRR			15.1%									
Annual Capacity and Fuel Charges			7.1	7.1	7.1	7.1	7.1	7.2	7.3	7.4	7.5	7.6
LIFE CYCLE COST TO GOVERNMENT			55.2									

Row	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
7	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20	year 21	year 22	year 23	year 24	year 25
8	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
20	6.00%	6.00%	6.00%	6.00%	6.00%										
24	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
26	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6
28	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
29	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
30	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
31	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
32	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
33	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
34	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
35	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
36	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
43	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
44	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
45	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0	2460000.0
46	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
51	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
52	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
53	3.75	3.85	3.96	4.07	4.18	4.30	4.42	4.54	4.67	4.80	4.94	5.08	5.22	5.36	5.51
55	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
56	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
57	3.75	3.85	3.96	4.07	4.18	4.30	4.42	4.54	4.67	4.80	4.94	5.08	5.22	5.36	5.51
63	.4%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%
64	5.803	5.820	5.838	5.855	5.873	5.890	5.908	5.926	5.944	5.962	5.979	5.997	6.015	6.033	6.051
65	5.803	5.820	5.838	5.855	5.873	5.890	5.908	5.926	5.944	5.962	5.979	5.997	6.015	6.033	6.051

	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
71	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
72	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000
77	1.018	1.021	1.024	1.027	1.030	1.033	1.037	1.040	1.043	1.046	1.049	1.052	1.055	1.058	1.062
78	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
79	.40%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%
82	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
92	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%
93	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
98	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
104	4.7	4.7	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.9	4.9	4.9	4.9
105	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.5
106	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
108	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
110	16.3	16.4	16.5	16.6	16.7	16.8	16.9	17.0	17.1	17.3	17.4	17.5	17.6	17.8	17.9
112	7.7	7.8	7.9	8.0	8.1	8.3	8.4	8.5	8.6	8.7	8.8	9.0	9.1	9.2	9.4
118	9.2	9.5	9.7	10.0	10.3	10.6	10.9	11.2	11.5	11.8	12.1	12.5	12.8	13.2	13.6
119	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
120	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.1	1.1
122	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5	.5
124	12.4	12.7	13.0	13.2	13.5	13.8	14.1	14.4	14.7	15.1	15.4	15.7	16.1	16.4	16.8
127	3.9	3.7	3.5	3.4	3.2	3.0	2.8	2.6	2.4	2.2	2.0	1.8	1.6	1.3	1.1
129	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0

Row	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
131	1.5	1.5	1.5	1.5	1.5	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
134	2.3	2.1	2.0	1.8	1.6	3.0	2.8	2.6	2.4	2.2	2.0	1.8	1.6	1.3	1.1
137	.8	.8	.7	.6	.6	1.1	1.0	.9	.8	.8	.7	.6	.5	.5	.4
140	1.[illegible]	1.4	1.3	1.2	1.1	1.9	1.8	1.7	1.6	1.4	1.3	1.2	1.0	.9	.7
141	======	======	======	======	======	======	======	======	======	======	======	======	======	======	======
145	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
148	1.5	1.4	1.3	1.2	1.1	1.9	1.8	1.7	1.6	1.4	1.3	1.2	1.0	.9	.7
150	1.5	1.5	1.5	1.5	1.5	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
152	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
154	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
156	3.0	2.9	2.8	2.7	2.6	1.9	1.8	1.7	1.6	1.4	1.3	1.1	1.0	.8	.7
157	======	======	======	======	======	======	======	======	======	======	======	======	======	======	======
164	7.7	7.8	7.9	8.0	8.1	8.3	8.4	8.5	8.6	8.7	8.8	9.0	9.1	9.2	9.4

APPENDIX F: Third-Party Gas Turbine Cogeneration Economics (Installation and PURPA Purchase)

C E R L
CASE ... Cogeneration GAS TURBINE Electricity sales to base and to utility
RUN DATED: 6/15/88

ASSUMPTIONS:	base year	year 1	year 2	year 3	year 4	year 5	year 6	year 7	year 8	year 9	year 10
					% Debt	80.0%					
OPERATING TERM (years)		23			% Equity	20.0%					
					Interest Rate						
BASE YEAR		1988			On Debt	11.0%					
FIRST YEAR OF PLANT OPERATION		1990									
· MAXIMUM THERMAL DEMAND MMBtu/hr	260.0										
BASIS (1988$ millions)		48.0									
END OF LIFE SALVAGE VALUE (20% OF ORIGINAL COST)		9.6									
DEPRECIATION RATES 1986 TAX LAW		5.00%	10.00%	9.00%	8.00%	7.00%	7.00%	6.00%	6.00%	6.00%	6.00%
POWER GENERATION DATA											
· Average Steam demand (MMBTU/Hr)	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
· Electricity demand (mw) AVG	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6
· PURPA Electricity sales (mw) · AVG	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1
· Loading											
· planned outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
· forced outage rate		2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
· dispatch reserve		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
· Load factor		95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
· Annual operating hours		8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
· summer hours		2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
· other hours		5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
· peak hours		2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
· off-peak hours		5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
· Boiler output required (million Btu/yr)		6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0
· Energy input · GAS (%)		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
		.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
· Energy input · GAS (million Btu/yr)		6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0
		.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
FUEL DATA											
· Fuel Cost · Input											
· GAS cost ($/million Btu)		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
· Escalator		.7%	.7%	.7%	.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
· Average fuel cost ($/million Btu)		3.02	3.04	3.07	3.09	3.17	3.26	3.35	3.45	3.54	3.64
· Fuel Cost · Output											
· GAS cost ($/million Btu)		3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
		.7%	.7%	.7%	.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
· Average fuel cost ($/million Btu)		3.02	3.04	3.07	3.09	3.17	3.26	3.35	3.45	3.54	3.64
VALUE OF STEAM CONSUMED											
· Value to (base year $/MMBTU)	2.725										
· Value to Others (base year $/MMBTU)	2.725										
· Steam value escalation rate (real)			-.1%	-.8%	-.2%	.1%	.4%	.6%	.6%	.4%	.4%
· Value forecast ($/MMBTU)		2.725	2.722	2.700	2.695	2.698	2.709	2.725	2.741	2.752	2.763

A	B	C	D	E	F	G	H	I	J	K	L	M
VALUE OF ELECTRICITY CONSUMED												
· Elect. value (base year cents/kwh)		5.000										
· Electricity escalation rate (real)		.000		.000	.000	.000	.000	.000	.000	.000	.000	.000
· Elect. value to Base (cents/kwh)			5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000
· Electricity sold to utility		6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800
OPERATING AND MAINTENANCE EXPENSES												
· Fixed cost ($ millions) ADL est.		1.840	1.840	1.838	1.823	1.820	1.822	1.829	1.840	1.851	1.858	1.866
· O & M escalation rate (real)		.00%		-.10%	-.80%	-.20%	.10%	.40%	.60%	.60%	.40%	.40%
INSURANCE			2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
INTEREST PAYMENT SCHEDULE			11.00%	10.30%	9.60%	8.80%	.08	6.90%	5.80%	4.50%	3.20%	1.70%
PRINCIPAL REPAYMENT SCHEDULE			6.00%	6.70%	7.40%	8.20%	9.10%	10.10%	11.20%	12.50%	13.80%	15.30%
DISCOUNT RATES (zero inflation)												
		15.00%										
FEDERAL/STATE TAX RATE			37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%
INVESTMENT TAX CREDIT			.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
ENERGY TAX CREDIT			.00%									
PRO FORMA INCOME STATEMENT ($ millions)			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
REVENUES												
Value of steam consumed-capacity charge			2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Value of steam-fuel charge			2.4	2.5	2.5	2.5	2.6	2.6	2.7	2.8	2.9	3.0
Value of electricity consumed by Base			8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Electricity sales			21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Total Revenues			34.7	34.8	34.8	34.8	34.8	34.9	35.0	35.1	35.2	35.3
TOTAL VALUE OF STEAM REVENUES			4.7	4.7	4.7	4.7	4.8	4.8	4.9	5.0	5.1	5.2
PRESENT VALUE OF STEAM REVENUES			45.2									
OPERATING EXPENSES												
Total Fuel Cost			19.8	20.0	20.1	20.3	20.8	21.4	22.0	22.6	23.3	23.9
Standby charges ($4.00/kw/month,35,000kw required)			1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Operations and Maintenance			1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.9	1.9	1.9
Property Taxes and Insurance			.5	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Total Operating Expenses			23.8	24.4	24.6	24.7	25.3	25.9	26.5	27.1	27.7	28.4
OPERATING CASH MARGIN			10.9	10.3	10.2	10.1	9.6	9.0	8.5	8.0	7.4	6.9
INTEREST EXPENSE			4.2	4.0	3.7	3.4	3.0	2.6	2.2	1.7	1.2	.7

A	B	C	D	E	F	G	H	I	J	K	L	M
DEPRECIATION			2.4	4.8	4.3	3.8	3.4	3.4	2.9	2.9	2.9	2.9
TAXABLE INCOME			4.3	1.6	2.2	2.8	3.2	3.0	3.4	3.4	3.3	3.3
INCOME TAXES			1.6	.5	.8	1.0	1.1	1.1	1.2	1.2	1.2	1.2
TAX CREDITS			.0									
AFTER TAX INCOME			2.7	1.0	1.4	1.8	2.1	2.0	2.2	2.2	2.2	2.2
			======	======	======	======	======	======	======	======	======	======
CASH FLOW CALCULATIONS			1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
AFTER TAX INCOME			2.7	1.0	1.4	1.8	2.1	2.0	2.2	2.2	2.2	2.2
DEPRECIATION			2.4	4.8	4.3	3.8	3.4	3.4	2.9	2.9	2.9	2.9
INVESTMENT & PRINCIPAL PMT	4.8	4.8	2.3	2.6	2.8	3.1	3.5	3.9	4.3	4.8	5.3	5.9
WORKING CAPITAL			4.2	.0	.0	.0	.0	.0	.0	.0	.0	.0
	------	------	------	------	------	------	------	------	------	------	------	------
CASH FLOW	-4.8	-4.8	-1.4	3.2	2.9	2.5	1.9	1.4	.8	.3	-.3	-.8
	======	======	======	======	======	======	======	======	======	======	======	======
PRESENT VALUE AT 15%			.0									
IRR			14.9%									
Annual Capacity and Fuel Charges			4.7	4.7	4.7	4.7	4.8	4.8	4.9	5.0	5.1	5.2
LIFE CYCLE COST TO GOVERNMENT			37.4									

	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
7	year 11	year 12	year 13	year 14	year 15	year 16	year 17	year 18	year 19	year 20	year 21	year 22	year 23	year 24	year 25
8	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------	-------
20	6.00%	6.00%	6.00%	6.00%	6.00%										
24	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3	97.3
25	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6	20.6
26	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1	38.1
28	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
29	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
30	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
31	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%	95.00%
32	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0	8322.0
33	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0	2847.0
34	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0	5475.0
35	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5	2788.5
36	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5	5533.5
42	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0
43	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
44	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
45	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0	6560000.0
46	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
51	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
52	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
53	3.75	3.85	3.96	4.07	4.18	4.30	4.42	4.54	4.67	4.80	4.94	5.08	5.22	5.36	5.51
55	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
56	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
57	3.75	3.85	3.96	4.07	4.18	4.30	4.42	4.54	4.67	4.80	4.94	5.08	5.22	5.36	5.51
63	.4%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%	.3%
64	2.774	2.783	2.791	2.799	2.808	2.816	2.825	2.833	2.841	2.850	2.859	2.867	2.876	2.884	2.893

	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
66															
67															
68															
69															
70															
71	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000	.000
72	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000
73	6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800	6.800
74															
75															
76															
77	1.873	1.879	1.884	1.890	1.896	1.901	1.907	1.913	1.919	1.924	1.930	1.936	1.942	1.948	1.953
78															
79	.40%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%	.30%
80															
81															
82	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
83															
84															
85															
86															
87															
88															
89															
90															
91															
92	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%	37.00%
93	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%	.00%
94															
95															
96															
97															
98	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
99															
100															
101															
102															
103															
104	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
105	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9	4.0	4.1	4.2	4.3	4.5
106	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
107															
108	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
109	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
110	35.4	35.5	35.5	35.6	35.7	35.8	35.9	36.1	36.2	36.3	36.4	36.5	36.6	36.8	36.9
111															
112	5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.0	6.1	6.2	6.3	6.4	6.6	6.7	6.8
113															
114															
115															
116															
117															
118	24.6	25.3	26.0	26.7	27.4	28.2	29.0	29.8	30.6	31.5	32.4	33.3	34.2	35.2	36.2
119	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
120	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.0
121															
122	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
123	------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
124	29.1	29.8	30.5	31.2	32.0	32.8	33.5	34.4	35.2	36.1	37.0	37.9	38.8	39.8	40.8
125															
126															
127	6.3	5.7	5.1	4.4	3.8	3.1	2.4	1.7	1.0	.2	-.6	-1.4	-2.2	-3.0	-3.9
128															
129	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
130															

	I	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB
131		2.9	2.9	2.9	2.9	2.9	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
134		3.4	2.8	2.2	1.5	.9	3.1	2.4	1.7	1.0	.2	-.6	-1.4	-2.2	-3.0	-3.9
137		1.2	1.0	.8	.5	.3	1.1	.8	.6	.3	.1	-.2	-.5	-.8	-1.1	-1.4
140		2.2	1.8	1.4	1.0	.6	2.0	1.6	1.1	.6	.1	-.4	-.9	-1.4	-2.0	-2.5
141		======	======	======	======	======	======	======	======	======	======	======	======	======	======	======
145		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
148		2.2	1.8	1.4	1.0	.6	2.0	1.6	1.1	.6	.1	-.4	-.9	-1.4	-2.0	-2.5
150		2.9	2.9	2.9	2.9	2.9	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
152		.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
154		.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
155		------	------	------	------	------	------	------	------	------	------	------	------	------	------	------
156		5.1	4.7	4.3	3.9	3.4	2.0	1.5	1.1	.6	.1	-.4	-.9	-1.4	-2.0	-2.5
157		======	======	======	======	======	======	======	======	======	======	======	======	======	======	======
164		5.3	5.4	5.5	5.6	5.7	5.8	5.9	6.0	6.1	6.2	6.3	6.4	6.6	6.7	6.8

APPENDIX G: Checklist for Identifying Optimal Third-Party Projects and Bidders

The following checklist should be used in conjunction with existing third-party contracting requirements as a guide for successfully developing third-party projects.

Project Identification

1. Is the potential project in an area needing electrical generating capacity as indicated in part by low reserve margins of local utilities and high regional economic growth?

2. Is an average avoided-cost payment (for energy and capacity) for cogenerated electricity of more than $0.06/kWh available, i.e., have other cogenerators been able to negotiate rates in this range or has the local utility stated it will pay in that range or above?

3. Does the potential project have concentrated thermal energy peak requirements of 25 MBtu/hr or more?

4. Is a new or replacement boiler needed?

5. Are adequate land (at least several acres) and water available for a cogeneration plant?

6. Are transportation sources, including gas pipelines, available for fuel supply to the project?

7. Can environmental and other permits be obtained quickly?

Pre-Bid Feasibility

1. Have historical peak, average annual, and monthly thermal energy demands for the installation over the past 10 years been identified and corrected for projected conservation and changes in base mission?

2. Does the installation have an existing steam or high-temperature hot water system for distribution from a central heat plant?

3. Has an engineering projection of costs for building a Government central heating plant been made?

4. Have engineering projections of capital and operating costs for coal-and gas-based cogeneration plants been made?

5. Does the life-cycle cost of a Government-owned steam boiler heat plant, if paid over 25 years to a private contractor, support revenues which together with electricity payments from the local utility give the third-party contractor a rate of return on equity (assuming 80 percent debt financing) of 15 percent or more?

Bidding Process

1. Do requests for qualifications and experience statements require lists and references for comparable projects, either commercial or Government (size, technology, cost), from potential bidders?

2. Have qualifications and experience statements been solicited from bidders' list?

3. Has the final bidders' list been narrowed to only those firms that have successfully completed similar projects?

4. Have credit checks such as Dunn & Bradstreet been obtained on the final bidders along with personal or corporate financial disclosure statements (obtainable from any bank)?

Request for Solicitations and Project Specifications

1. Does the request for solicitation specify the desired configuration of the plant as to:

- Cogeneration

- Range of fuels

- Generation technologies?

2. Does it specify the method of pricing thermal energy and do the proposed escalator clauses for each element parallel actual cost increases expected to be incurred by the contract?

3. Is the contractor asked to provide information on fuel supply sources, method of pricing, and transportation modes?

4. Is the proposed design and construction time feasible for the size and type of fuel/technology (1 to 2 years for gas plants; up to 5 years for large e.g., 500 MBtu/hr, coal plants)?

Bid Evaluation and Selection

1. Has the project financing structure for each bidder, including all investors and lenders, been identified?

2. Does it limit liability to the assets of the project or does the Government have recourse to assets of the partners?

3. Are insurance and specific guarantees of performance provided by project partners to cover any liability to the Government which could not be satisfied from the assets of the project after creditors are paid?

4. Have major participants in the project on whose performance the project depends also invested cash in the equity of the project?

5. Has the bidder specified all documents and legal reviews that must be provided at the closing of the contract?

6. Has the Government performed a life-cycle cost comparison for each bid project against that of a Government plant with similar thermal output?

7. Have the assumptions on which the third-party life-cycle cost depends been identified and assessed as to their risk of Change?

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